Electric Utility Cost of Service Study

City of Norway, Michigan

SEH No. NORWY0301.00

Revised February 2004

February 9, 2004

RE: Electric Utility Cost of Service Study
City of Norway, Michigan
SEH No. NORWY0301.00

Mr. Karl Zueger, Utilities Director
City of Norway
915 Main Street
PO Box 99
Norway, MI 49870-0099

Dear Mr. Zueger:

Enclosed are 12 copies of the Electric Utility Cost of Service/Rate Study. I look forward to our upcoming discussions regarding this project.

Please call if you have any questions.

Sincerely,

David Krause, PE
Project Manager

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Electric Utility Cost of Service Study

Prepared for:
City of Norway
Norway Michigan

Prepared by:
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Distribution List

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Executive Summary

Historical Perspective and Rate Study Purpose

The present rate structure of the City of Norway Electric Utility has been in place for many years, with no significant rate increases since 1994. Over the years, changes have taken place in the city population, community businesses and wholesale power costs. At the present time, utility staff members are considering some significant electric generation and distribution system improvements. The proposed improvements will result in improved system reliability and safety. These factors, along with the desire to take a more modern approach to rate-making, have led Norway to investigate its present electric rates. Accordingly, Norway authorized Short Elliott Hendrickson Inc.® (SEH) to perform a Cost of Service and Rate Study. The purpose of the study is to identify the utility's cost of providing electric service to its customers and to propose rates reflecting the utility's cost structure.

Spreadsheet Model

SEH developed a series of integrated spreadsheets and graphical charts as a key component of the electric rate study. The spreadsheet model identifies the cost of service and evaluates the impacts of proposed rate changes on both utility revenues and customer charges. The spreadsheets and charts represent a financial model of Norway's municipal electric utility. The model is very sophisticated but has relatively few user inputs. These inputs can be adjusted by utility personnel to accommodate changes in utility finances and to predict the financial impact of rate adjustments on utility revenues and customer energy costs. The spreadsheet model is offered for use by the utility's staff with the understanding that Norway will use the software exclusively for the City of Norway and that electronic copies of the software will not be released to other parties without first contacting SEH or its successors for release authorization.

Comparative Electric Rates

Norway's present electric rates are generally comparable to those of neighboring electric utilities. The Rate Study compares Norway's rates with the rates of neighboring Escanaba and Gladstone Municipal Utilities and We Energies. Typically Norway rates are lower than their neighbors.

Cost of Service

Capital improvements, purchased power and labor have historically been Norway's most significant costs. These costs are expected to increase in coming years. If the re-regulation agreement with We Energies were to go away, an increase in the demand component of costs from the present 5% to 14% of total expenditures could be anticipated. This would equate to a $0.0065 per kWh increase in rates for recovery, or an additional $195,000. Additionally we anticipate an increase in transmission service costs of 50%-100% in the next five years. At the present rate of $0.80214/kW monthly, this would represent an additional $27,000 in costs or $0.0009/kWh in increased rates for recovery. There are other variable costs not included in this rate analysis. Future adjustments to this rate structure can be anticipated based on changing market conditions. Norway's' expenses in recent years appear to be representative of future utility costs. Norway's revenues come primarily from residential, commercial and industrial customers. During each of the past five years, annual customer revenues have generally kept up with operating costs, allowing the utility to contribute to the city general fund and other non-utility funds as well as making occasional additions to utility reserves.

Executive Summary (Continued)

Cost of Service Rates

The cost of service is one of the most important considerations in establishing electric rates. The American Public Power Association (APPA) offers a widely accepted methodology to establish cost of service rates for municipal utilities. We have applied this methodology to the City of Norway, with some minor modifications to accommodate local situations. The cost allocation process has identified a slight rate disparity between customer classes. The residential customer class appears to be contributing less revenue to the utility with respect to their electric kWh consumption while the commercial and industrial customers are contributing somewhat more.

Rate Design Theory

A section of the report is offered on basic rate design theory to provide a general review of rate design and to introduce several trends in electric rate making. The section should encourage discussion among utility and city personnel to identify the philosophies that might best be incorporated into Norway's rates.

Rate Unbundling

Customer choice is a key concept in the regulatory changes occurring within the electric industry. Although recent events on both the east and west coasts have slowed the pace of regulatory change in the Midwest, electric consumers may some day be allowed a choice in their suppliers and in the way they purchase energy. To provide customers with the choices they want, utilities must eventually unbundle their rates. The APPA methodology has been used in this study to identify the unbundled cost of service. There are, as yet, no firmly established procedures in place for unbundling electric rates.

Perhaps the best way to move toward an unbundled rate structure is incrementally, one step at a time. Although it may be premature for Norway to fully unbundle their rates now, it makes sense to establish a distribution wheeling rate to anticipate customers that may wish to purchase some of their energy services from other providers. Starting with the distribution wheeling rate, the city can set up a billing structure that will accommodate unbundling. By separating functions and costs, Norway can avoid losing revenue if customers choose to purchase specific energy services elsewhere.

Distribution Wheeling Rate

Electric distribution will remain the key service offered by the City of Norway. A well-maintained, reliable distribution system presents a nearly insurmountable economic barrier to other organizations wishing to enter Norway's present service area. A distribution wheeling rate can be established to provide sufficient revenue to maintain Norway's distribution system regardless of whom the customers purchase their energy from. Each customer would be assessed the distribution wheeling rate on a per kWh basis for electricity from the utility or wheeled across Norway's distribution system from an outside supplier.

The distribution wheeling rate can be based on Norway's cost of service for providing electric distribution to its customers. The distribution wheeling rate can be embedded in each of the present residential, commercial, small industrial and industrial rates until such time that utility deregulation makes it worthwhile for the utility to establish a separate line item for distribution wheeling in the monthly customer billing statements.

Executive Summary (Continued)

Cost of Energy Adjustment Clause

The City of Norway does not presently have an energy cost adjustment clause in the electric rate structure. The utility may wish to establish an energy cost adjustment clause to accommodate We Energies' wholesale fuel clause rate adjustment. The We Energies monthly rate adjustments could then be passed on to Norway's customers without a formal rate hearing. In addition, the council could establish a maintenance cost adjustment clause so that unanticipated or extraordinary maintenance and capital expenditures can be recovered directly through customer revenues. Maintenance efforts associated with storm damage might be an example of costs that could be recovered through the maintenance cost adjustment clause without a permanent rate increase.

Monthly Customer Charge

The City of Norway has a monthly customer charge for residential, commercial, small industrial and industrial customers to recover some of the utility's fixed customer service costs. These are costs that do not vary with kWh energy or kW demand and are incurred by the utility regardless of how much energy is consumed by customers. The monthly customer charge helps reduce Norway's dependence on stable energy sales to recover fixed costs on a per kWh basis. In addition, the monthly customer charge would apply to all customers obtaining energy through the utility's distribution system, regardless of whether they buy the energy from Norway or, in the future, from another provider. We recommend making modest increases in the monthly customer charge over the next several years to help recover more of Norway's fixed costs.

Proposed Rates

Norway has not increased the electric rates since 1994, nearly ten years ago. The present rates have provided sufficient customer revenues to allow the City of Norway to meet its energy cost obligations, make improvements to the generation plant and distribution system, add to utility reserves and provide transfers to the city's general fund and to other non-utility funds. At the present time, utility staff members are forced to consider significant electric generation and distribution system remedies. A rate increase will help the utility meet its current and future obligations. In addition, several adjustments should be made to better balance the burden of electric costs among Norway's electric customers. The proposed rate increase of approximately 1.5 cents/kWh is comprised of two components: $0.6 cents based on increasing costs in purchased power/energy and insurance requirements and $0.9 cents based on debt repayment to fund the recommendations made in the Electrical System Review.

Our proposed rates are based on a number of factors as discussed in this study. Norway's existing rates represent the most important of these factors, followed perhaps by cost of service, the rates of neighboring utilities, and allocating utility costs fairly among the customer types. To meet the utility's anticipated obligations we recommend a residential rate increase of nearly 30%, a commercial rate increase of nearly 19% and an industrial rate increase of about 13%. These increases will not only boost annual revenues, but will also provide a better balance in the cost of operating the utility between the residential, commercial and industrial customers. The proposed rate increases are substantial, particularly for the residential customers. Norway may wish to implement the rate increases gradually, in several increments over a period of two to three years to allow the customers to better budget for the higher electric costs.

Executive Summary (Continued)

Norway has a rate for small industrial customers. Presently, only four customers are served by the small industrial rate. We recommend that the small industrial rate be eliminated and that these four customers be transferred into the industrial rate.

One of the changes we recommend is a gradual increase in the monthly customer charge. Changes to the monthly customer charge should be made gradually and made with care because they affect small customers much more significantly than large users. The customer charge represents a much greater portion of the monthly bill for a small customer than it does for a large energy user. A rate increase may result in more financial hardship for small customers than it does for large users.

Norway's monthly rates for all security lighting options are somewhat lower than the estimated monthly cost of service. SEH recommends that the present $6.90 monthly security lighting rate be increased to $8.00 per month this year, $9.00 per month next year and to $10.00 per month the following year.

Revenues Under Existing and Proposed Rates

The existing and proposed rates can be applied to historic energy consumption patterns in Norway to identify the impact on utility revenues. Applying the existing and proposed rates to the past five years of energy consumption data results in a significant increase in utility customer revenues from residential, commercial and industrial customers. The projected revenues from small industrial customers are difficult to predict since past kW demand data for these customers is unavailable. The small industrial customer class is nearly insignificant, however, representing only about 1% of total utility annual customer revenues. Reclassifying these customers under the industrial rate will not have a material effect on utility revenues.

Customer Impact of Proposed Rates

The proposed rate changes have a very significant impact on the average City of Norway residential customer. The average residential customer electric bills will increase by about 30%. Small residential customers will experience an increase of about 33% or $7.25 per month. Large residential customers will face an increase of perhaps 29%. The percent change in energy costs for small customers is somewhat higher than for large customers due to the monthly customer charge. Increases in the monthly service charge have a greater effect on small customers than for large energy users. Commercial customers will experience an increase in electric energy costs of about 18.5%. An alternate method of assessing the rate increases proposed it to consider the changes on a $/kwh basis. Using 30 million kwh as the base sales figure, the proposed increase of 1.5 cents/kwh can be represented as 0.9 cents/kwh for system improvements and 0.6 cents/kwh for operating and other expenses. The proposed residential and commercial rates will be somewhat higher than the rates for Gladstone and Escanaba but still competitive. The proposed rates will still be lower than the residential and commercial rates charged by We Energies.

The proposed rate changes will have a different impact on each industrial customer. Each industrial customer has a unique relationship between monthly peak kW demand and monthly kWh energy use. As part of the study, we looked at the impact that the proposed rates will have on several of Norway's key customers. Based on the demand and energy consumption during 2002, the proposed rates will result in electric energy cost increases of 10.4% and 10.8% for Norway's largest industrial customers.

Recommendations

During recent years the present rates have allowed the utility to meet its obligations and to help fund other city functions. Utility costs are increasing and a rate increase will be required to sustain the level of past funding for utility improvements and non-utility city functions. In addition, utility management is planning some significant capital improvement projects that will help maintain electric system reliability and safety. It may be difficult to fund these projects from utility reserves and annual cash flow. The improvements could instead be funded by tax exempt revenue bonds. The proposed rate increase would provide revenues to retire the bonds.

In the study we are proposing a significant rate increase. The increase is based in part on the planned capital improvement projects. The proposed rate increase need not be made immediately but can instead be made in several increments during the next two or three years as plans for the proposed capital improvements move forward. The proposed rate changes will also help correct the revenue imbalance associated with the present rate structure. Further adjustment to the electric energy rates may be required in future years to meet utility obligations and to maintain a good balance among all customer groups in sharing the cost of operating the electric utility.

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Electric Utility Cost of Service Study

Prepared for City of Norway

1.0 Rate Study Historical Perspective

The present electric rates for the City of Norway have been in place for nearly ten years, with no adjustments made for inflation. This is quite an accomplishment but impossible to sustain. Over the years, changes have taken place in the city population, community businesses and wholesale power costs. The city's hydropower resource provides much of the community's power needs but some power must still be purchased. The cost of this purchased power is going up. In addition, significant improvements will soon need to be made to the hydropower equipment and to the electrical substations. These factors, along with the desire to take a more modern approach to rate-making, have led Norway to investigate the current electric rates. Accordingly, the City of Norway authorized Short Elliott Hendrickson Inc. (SEH) to perform a Cost of Service and Rate Study. The purpose of the study is to identify the utility's cost of providing electric service to its customers and to propose rate changes that will reflect the utility's present cost structure.

2.0 Spreadsheet Model

SEH developed a series of integrated spreadsheets and graphical charts as a key part of the electric rate study for Norway. The spreadsheets identify the cost of service for Norway and evaluate the impact of proposed rate changes on both utility revenues and customer energy costs. These spreadsheets and charts are presented in the following pages, supported by text that explains the unbundled cost of service rate study process. The spreadsheets and charts represent a financial model of Norway's municipal electric utility. The model is very sophisticated but has relatively few user inputs. The primary user inputs are highlighted yellow. These inputs can be adjusted to accommodate changes in utility finances and to predict the financial impact of rate adjustments on both utility revenues and on customer energy costs. It is important to look at both the utility revenue perspective and the customer energy cost perspective when contemplating a rate adjustment.

The spreadsheet model is offered for use by the utility staff with the understanding that Norway will use the software exclusively for the City of Norway and that electronic copies of the software will not be released to other parties without first contacting SEH for release authorization.

3.0 Comparative Electric Rates

3.1 Comparison of Average Utility Revenue

Norway's present electric rates are generally comparable to those of neighboring electric utilities. Table 1 and the associated chart present the average residential and commercial utility rates for several nearby utilities serving customers in Northern Michigan. The data shows Norway as having essentially the lowest average rate per kWh for all customer classes shown. The community should be proud of this accomplishment. Norway's low rates are due largely to the hydropower resource and to the fact that the community has not increased electric rates for nearly ten years.

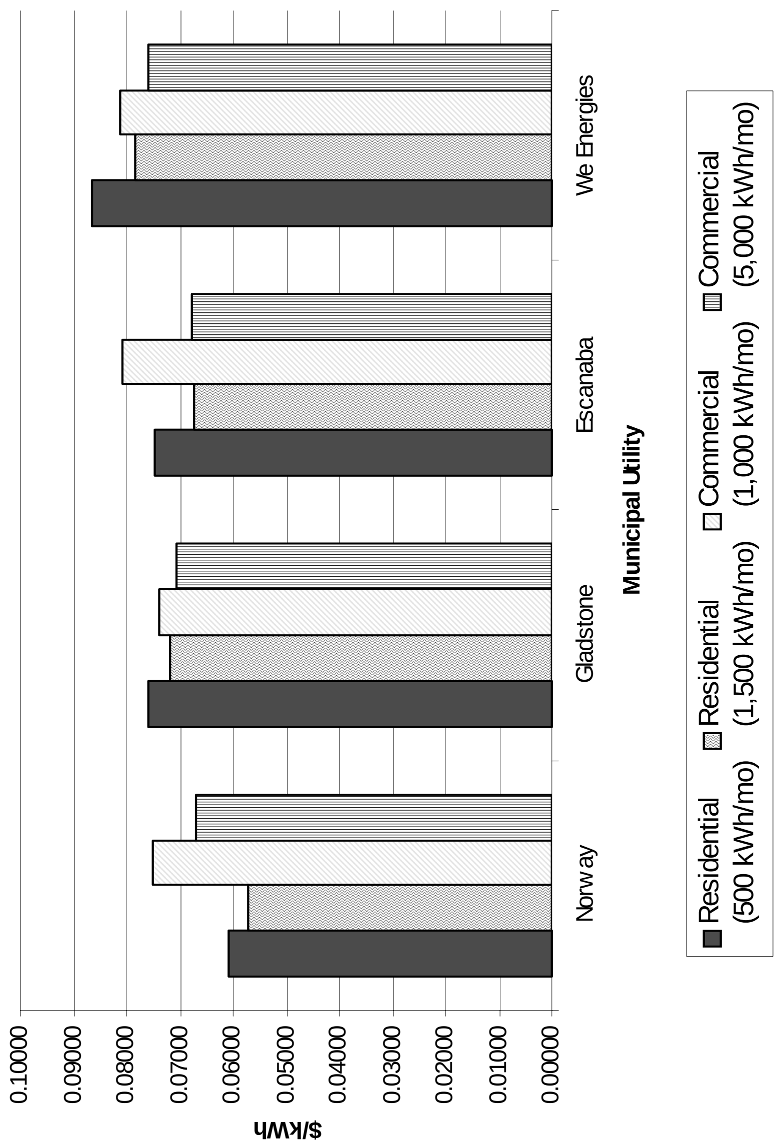
Care must be taken when comparing the average rates of several utilities. The average rate data represents not only the basic $/kWh rate of each utility but also the effect of any monthly service charges. Monthly service charges, for those utilities that assess them, have a more significant impact on small customers than large customers. The customer classifications of individual utilities may also make it difficult to compare the utilities. Each utility has its own customer classifications. A commercial customer for one utility might be classified as a small industrial customer for another. Some utilities have multiple commercial rate structures to accommodate large and small commercial customers. Other utilities may have special rates that do not easily fit within the classic residential/commercial/industrial breakdown. Each utility has its own unique mix of customer types and sizes.

Industrial customers are not included in the table due to the monthly demand charge. The demand charges of industrial customers can have a profound effect on average revenues per kWh. Customers having low load factors will provide much higher average revenues per kWh to the utility than customers with high load factors and relatively minimal demand charges.

Table 1
Average Utility $/kWh Rates by Customer Class

Municipal Utility	Residential (500 kWh/mo)	Residential (1,500 kWh/mo)	Commercial (1,000 kWh/mo)	Commercial (5,000 kWh/mo)
Norway	0.06100	0.05700	0.07500	0.06700
Gladstone	0.07600	0.07200	0.07400	0.07080
Escanaba	0.07487	0.06724	0.08090	0.06776
We Energies	0.08640	0.07846	0.08130	0.07586

Chart 1 – Average Utility $/kWh Rates by Customer Class



3.2 Rate Comparison with Escanaba Municipal and Gladstone Municipal

The nearby cities of Gladstone and Escanaba operate municipal utilities to provide electric energy to residents and businesses within their city limits. These two utilities are generally considered Norway's primary competitors. The rates of Norway, Escanaba Municipal and Gladstone Municipal are compared in Table 2 along with We Energies serving Iron Mountain and the surrounding areas.

3.3 Residential Rate Comparison

Norway's present rates are very competitive with those of neighboring Escanaba Municipal and Gladstone Municipal. The City of Norway has significantly lower energy rates per kWh than both Escanaba and Gladstone. Norway's monthly customer charge is nearly the same as the monthly charges for Gladstone and Escanaba.

3.4 Commercial Rate Comparison

The City of Norway offers generally lower commercial rates than both Escanaba and Gladstone. Norway's monthly customer charge, however, is significantly higher than the charge for both Escanaba and Gladstone.

3.5 Small Industrial Rate Comparison

Norway has very few small industrial customers. Norway's rates for these customers are very high compared to those of the neighboring utilities. Note that Gladstone offers two small industrial rates, one rate for three-phase customers and one rate for single-phase customers.

3.6 Industrial Rate Comparison

The City of Norway offers a three-phase industrial rate comparable to Escanaba Municipal and Gladstone Municipal. Gladstone has a slightly lower $/kW demand charge but a much higher monthly customer charge. Escanaba's industrial $/kWh energy rate is nearly equal to the rate that Norway offers, but Escanaba has no monthly customer charge. Norway's monthly demand charge is significantly higher than the demand charge for the neighboring utilities. The demand charges for Escanaba and Gladstone appear to be much lower than their cost of service and should be examined more closely by utility personnel.

3.7 Security Lighting

Norway's monthly charge for security lighting is significantly lower than the charge for Escanaba and Gladstone. It appears that the security lighting rate for Norway could be increased if it is not meeting the cost of service.

Table 2
Electric Rate Comparison with Neighboring Utilities

		Present Norway (City)	Escanaba	Gladstone
Residential				
Monthly Customer Charge ($)		3.00	2.39	3.00
Energy Charge ($/kWh)	1st 400 kWh	0.05500	0.07175	0.07000
Energy Charge ($/kWh)	Over 400 kWh	0.05500	0.06343	0.07000
Commercial (Single Phase)				
Monthly Customer Charge ($)		10.00	2.39	4.00
Energy Charge ($/kWh)	1st 500 kWh	0.06500	0.08942	0.07000
Energy Charge ($/kWh)	500 to 2,000 kWh	0.06500	0.06759	0.07000
Energy Charge ($/kWh)	Over 2,000 kWh	0.06500	0.06343	0.07000
Small Industrial				
Monthly Customer Charge ($)		20.00	0.00	10.00
Energy Charge ($/kWh)	1st 1,000 kWh	0.09500	0.05200	0.05500
Energy Charge ($/kWh)	1,000 to 20,000 kWh	0.06500	0.05200	0.05500
Industrial				
Monthly Customer Charge ($)		20.00	0.00	40.00
Energy Charge ($/kWh)	1st 50,000 kWh	0.05000	0.05200	0.04300
Energy Charge ($/kWh)	50,000 to 200,000 kWh	0.05000	0.04900	0.04300
Energy Charge ($/kWh)	Over 200,000 kWh	0.05000	0.04600	0.04300
Monthly Demand ($/KW)	All kW	6.00	3.27	4.00
Security Lighting				
Monthly Customer Charge ($)		6.90	9.63	10.04
Notes: Gladstone small Industrial Rates: Single Phase - $6.00 Monthly Customer Charge, $0.057/kWh				

4.0 Cost of Service

Prices in a regulated industry are generally based on costs. In a regulated industry, suppliers are typically allowed a specific profit margin, based on their cost of doing business. This is particularly true of investor owned utilities where the profit margin is distributed to company shareholders in the form of stock dividends. Identifying the cost of serving electric customers is critical to the regulatory process.

Municipal utilities are generally not as closely regulated as investor owned utilities. The primary regulatory effort is at the local level, through a municipal utility board, commission or city council. As non-profit enterprises, municipal utilities strive to offer their customers the lowest possible electricity prices while maintaining excellent service. In a sense, municipal utilities offer a form of competition to investor owned utilities by establishing benchmark levels of pricing and service. Identifying the cost of serving customers is critical to municipal utilities just as it is to investor owned utilities. The cost of service must be identified to ensure that the electric rates are set sufficiently high to cover current and projected costs and to assure that rates are set equitably for all customer classes.

4.1 Average Costs

Historically, electric rates have been based on average costs. To determine average costs, a utility must know the quantity of electricity they will sell and the customers they will serve. Average costs can then be calculated by dividing the cost of service by the quantity of electricity or the number of customers. This is generally straightforward for a utility whose service area and customer base is static or changes relatively slowly and predictably.

4.2 Marginal Costs

Portions of the electric industry are moving toward increased competition. In a competitive industry, pricing is generally based on the established competition instead of average costs. New suppliers wanting to enter a specific market must offer improved service or lower pricing than the established supplier offers. The marginal cost of doing business in the new market becomes the decision-making criteria, as opposed to the average cost of doing business in an existing service area. As competition increases, utilities must first evaluate what customers will pay and then choose the quantity of electricity to produce and the markets they will serve, instead of basing their activities on an average cost of doing business. The marginal cost of serving new customers or the increased load of an existing customer is seldom equal to the average cost of serving the present customers.

The marginal cost of serving a new customer or the increased load of an existing customer can be more difficult to determine than the average cost of service. The marginal cost will depend on the new customer size, location, load factor and load profile. Sunk costs, as well as overhead or common costs are seldom included in marginal costs. Sunk costs and overhead are not affected by an incremental increase or decrease in electric output. The new customer may require a capital investment or increased operation and maintenance costs for the utility.

4.3 Evaluating New Customers on the Basis of Average Costs

The balance of this section on cost of service is based on the average costs associated with serving Norway’s existing customers. Competition will most likely be introduced slowly to the market that Norway presently serves. Competition may never be realized in the distribution portion of the utility’s business. The average cost of service still provides a valuable basis for establishing electric rates. Caution should be used in applying the average cost of service information presented in this study to the potential cost of serving major new customers or a large increase in the load of an existing customer.

4.4 Norway Annual Expenses

Table 3A presents Norway's annual operating expenses during the past five years. The data in the table is taken primarily from City of Norway Electric Fund annual financial reports. In the City of Norway Electric Fund annual financial reports, one entry is provided for energy purchases. Using the wholesale power invoices for 2000 and 2001, SEH separated the energy portion from the demand portion of the wholesale bills. It is important to separate energy costs from demand costs when preparing a cost of service electric rate study. The table also includes a column for the 2003-2004 budgeted utility expenses and a column titled 'study year'. The study year column represents an expectation of annual utility expenses during the next several years.

Total utility operating expenses have varied significantly during the past five years. While some of the variation is due to purchased power, capital improvements and transfers to other city funds have resulted in wide changes to the annual operating expenses from year to year. The situation continues into the 2003-2004 budget year. The utility is planning some significant capital improvements to maintain reliability in the hydro generation and electric distribution systems. In addition, the utility anticipates significant purchased power costs during a period when one of the hydropower generators is out of service.

The wide variation in utility expenses during the past several years makes it difficult to select any of these years to represent the anticipated expenses in future years. For this reason we have established the study year column to provide a representation of utility expenses going forward. In the study year column, we have allocated no costs for new vehicles in account items 970 and no costs to account items 971 and 972, capital improvements for distribution and hydro. Utility staff plans to accomplish several utility vehicle purchases in the coming years and has established a forecast for these purchases. This forecast is included in the appendix and reflected in item 998, equipment replacement for the study year in Table 3A. Likewise, utility management is contemplating some significant capital improvements during the next several years to maintain the electric distribution and generation system reliability. The improvements can be financed by issuing municipal revenue bonds during this period of low interest rates. Assuming a conservative interest rate of 5.5% and a 20-year bonding period results in an annual payment of $243,674 to retire the bonds as shown in Table 3B. This figure is also shown for the study year in Table 3A under account item 999, capital projects.

In Table 3B we have included a line item for diesel-electric generation. Diesel generation could allow the electric utility to operate independently of the national electric grid in the event of an outage at the grid interconnection. At present, Norway's hydro generation must depend on the grid interconnection for stability control. In the event of a power outage, Norway is exposed to very high wholesale demand charges since the hydro generators must be taken off-line during the outage and cannot be re-started immediately when wholesale power becomes available again at the interconnection. While it may be desirable to install diesel generation now, it appears that the other electric system improvements listed in Table 3B should take priority. At some future time an entry for diesel generation could be made to Table 3B of the electric rate model to begin to identify the impact of diesel generation on the cost of service rates for Norway. The diesel generating units may also allow Norway to purchase wholesale energy from We Energies at an interruptible rate instead of buying firm power. As such, this detailed analysis is not included here because it falls beyond the scope of the unbundled cost of service study.

5.0 Norway Annual Revenues and Retained Earnings

Table 4 presents Norway's annual operating revenues during the past five years. The data in the table is taken primarily from City of Norway Electric Fund annual financial reports. Similar to Table 3A for utility expenses, Table 4 includes a column for the 2003-2004 budgeted utility revenues and a column titled 'study year'. The study year column represents an expectation of annual utility revenues during the next several years. The 2003-2004 budget year includes several extraordinary items such as an anticipated property sale under account 673 and some miscellaneous revenues under item 633. These one-time items are not reflected in the data chosen for the study year to represent the anticipated utility revenues going forward.

The total operating expenses from Table 3A are shown again at the base of Table 4. The operating expenses for each year can be subtracted from the utility revenues to identify the retained earnings. These retained earnings would normally be directed into the utility reserves. During several recent years, utility expenses exceeded the revenues, requiring Norway to dip into the reserves. For the study year, we used the spreadsheet model to calculate the annual electric sales and demand charges (account items 641 and 648) based on the electric rates proposed later in this report. The proposed rates result in retained earnings of about $177,000, representing approximately 7.3% of the annual utility operating income.

Table 3A
Annual Electric Utility Operating Expenses by Fiscal Year

	Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Acct. #	OPERATING EXPENSES	$	$	$	$	$	$	$
702	Salaries - Full Time	433,560.00	357,642.00	343,677.00	331,936.00	312,377.00	422,665.00	422,665.00
703	Salaries - Part Time	0.00	0.00	0.00	3,864.00	22,196.00	8,438.00	8,438.00
704	Salaries - Overtime	0.00	49,520.00	52,297.00	59,219.00	69,650.00	63,430.00	63,430.00
705	Employee Separation	0.00	6,615.00	0.00	14,500.00	0.00	0.00	0.00
706	Sick Time Buyback	0.00	0.00	0.00	0.00	0.00	0.00	0.00
707	Longevity pay	5,675.00	4,875.00	4,925.00	4,725.00	4,350.00	4,800.00	4,800.00
708	COLA Adjustment	0.00	0.00	0.00	0.00	1,205.00	0.00	0.00
709	Shift Differential - Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00
712	VEBA Contribution	0.00	0.00	0.00	0.00	5,450.00	5,430.00	5,430.00
715	Employer - FICA	32,693.00	32,122.00	30,489.00	33,155.00	31,875.00	38,250.00	38,250.00
716	Group Insurance	72,875.00	82,123.00	103,086.00	108,512.00	123,048.00	195,983.00	195,983.00
717	Self Insured Retention	0.00	0.00	0.00	0.00	3,204.00	9,000.00	9,000.00
718	Employer - MERS	3,841.00	25,229.00	36,306.00	52,036.00	44,633.00	68,250.00	68,250.00
719	Unemployment Compensation	9,981.00	8,749.00	3,976.00	3,045.00	1,429.00	4,460.00	4,460.00
720	Training/Membership/Travel/Education	0.00	3,570.00	3,561.00	4,237.00	5,007.00	13,500.00	13,500.00
740	Supplies (Operating & Office)	28,155.00	10,775.00	12,970.00	9,259.00	4,855.00	7,000.00	7,000.00
745	Printing/Postage/Stationary/Publications	0.00	5,852.00	6,245.00	6,819.00	9,624.00	7,000.00	7,000.00
750	Uniform/ Cleaning Expense	1,036.00	3,061.00	2,499.00	2,675.00	3,524.00	3,600.00	3,600.00
751	Gas & Oil	3,712.00	3,811.00	4,085.00	4,252.00	4,021.00	5,500.00	5,500.00
752	Transmission/Distribution Expense	62,316.00	37,951.00	34,880.00	42,874.00	31,276.00	50,000.00	50,000.00
753	Banners & Decorations	0.00	8,620.00	1,331.00	1,486.00	309.00	0.00	0.00
801	Toll Charges	11,292.00	14,148.00	16,168.00	19,144.00	12,888.00	23,500.00	23,500.00
802	Purchased Power - Demand	91,170.80	113,173.55	95,308.50	108,921.05	111,612.55	160,000.00	135,000.00
802	Purchased Power - Energy	169,317.20	210,179.45	177,001.50	202,281.95	207,280.45	255,000.00	210,000.00
803	Street Lighting	4,809.00	5,626.00	1,342.00	4,334.00	5,417.00	3,000.00	3,000.00
804	Meter Expense	473.00	1,687.00	38.00	5,007.00	2,328.00	5,000.00	5,000.00
819	Professional Services	18,958.00	13,599.00	5,208.00	86,260.00	50,190.00	31,500.00	31,500.00
861	Maintenance - Equip/Buildings	15,346.00	25,529.00	19,590.00	36,313.00	30,177.00	20,000.00	20,000.00
903	Computer Expense	4,109.00	3,488.00	5,130.00	1,493.00	385.00	1,000.00	1,000.00

Table 3A (Continued)
Annual Electric Utility Operating Expenses by Fiscal Year

	Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Acct. #	OPERATING EXPENSES	$	$	$	$	$	$	$
914	Insurance - Liab./Prop./Worker's Comp.	45,487.00	65,240.00	58,391.00	32,536.00	38,103.00	50,330.00	50,330.00
920	Telephone	0.00	2,797.00	3,612.00	3,993.00	4,546.00	4,200.00	4,200.00
922	Heating Fuel (Michcon)	0.00	2,481.00	1,738.00	2,492.00	406.00	2,500.00	2,500.00
925	Disposal Expense	0.00	7,425.00	0.00	4,636.00	9,964.00	3,000.00	3,000.00
942	Rental/Lease	0.00	9,412.00	9,406.00	9,400.00	9,700.00	11,250.00	11,250.00
955	Property Taxes	2,423.00	2,642.00	2,856.00	3,096.00	3,269.00	3,500.00	3,500.00
956	Misc. Expense	7,649.00	2,151.00	0.00	0.00	0.00	0.00	0.00
974	Bond Payment - Principal	0.00	110,000.00	110,000.00	115,000.00	125,000.00	165,000.00	165,000.00
993	Bond Issue Costs (Discounts)	21,184.00	1,184.00	21,184.00	21,184.00	21,245.00	21,245.00	21,245.00
995	Interest expense	109,004.00	103,905.00	99,358.00	94,499.00	92,822.00	137,982.00	137,982.00
--	Property Acquisition	0.00	0.00	0.00	0.00	0.00	0.00	0.00
970	New Vehicles $ Equip.	0.00	0.00	0.00	0.00	39,298.00	60,000.00	0.00
971	Capital Improvements - System	30,521.00	96,728.00	66,982.00	105,352.00	79,548.00	51,000.00	0.00
972	Capital Improvements - Hydro Plant	0.00	262,929.00	274,377.00	357,103.00	261,976.00	634,500.00	0.00
972-021	Dam Stabilization Project	0.00	0.00	0.00	0.00	14,552.00	0.00	0.00
972-022	Hydro Stabilization Project	0.00	0.00	0.00	0.00	65,150.00	0.00	0.00
982	To General Fund - One Time	0.00	0.00	150,000.00	0.00	0.00	0.00	0.00
982	To General Fund	29,436.00	124,045.00	125,202.00	129,365.00	859,112.00	190,216.00	180,000.00
997	To Cable TV Fund - One Time	0.00	55,000.00	0.00	250,000.00	0.00	0.00	0.00
998	To Equipment Replacement Fund	0.00	0.00	110,457.00	0.00	0.00	0.00	54,000.00
999	To Capital Projects Fund	100,000.00	0.00	35,000.00	35,000.00	35,000.00	35,000.00	274,781.20
	Total	**1,315,023**	**1,873,884**	**2,028,676**	**2,310,004**	**2,758,002**	**2,776,029**	**2,244,094**

Table 3B
Equipment Replacement Bond Calculations

Item	Cost ($)
#4 Generator Replacement	495,000.00
New Main Substation	1,200,000.00
New Hydro Substation	200,000.00
Distribution Improvements	1,945,000.00
4 MW Diesel Generation	0.00
Subtotal	3,840,000.00
4% Bond Origination Fee	153,600.00
Total	3,993,600.00
Annual Payment 30 yr	(274,781.20)
Annual Payment 20 yr	(334,181.77)
Annual Payment 15 yr	(397,864.79)

Note: Total Annual Payment based on 30 year, 15 year or 20 year municipal revenue bond @ 5.5% interest.

Note: 4MW Diesel Generation Approximate Installed Cost = $1,400,000

Table 4
Annual Electric Utility Operating Revenues by Fiscal Year

	Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Acct. #	Operating Income	$	$	$	$	$	$	$
402	Retirees Insurance Reimbursement	0.00	15,788.00	21,813.00	19,757.00	20,023.00	28,285.00	28,285.00
569	Bond Proceeds	0.00	0.00	0.00	0.00	986,766.00	0.00	0.00
633	Misc. Revenues	11,470.00	1,480.00	7,647.00	1,858.00	870.00	130,000.00	5,000.00
636	Line Installation Costs	12,897.00	8,472.00	21,593.00	17,928.00	13,612.00	10,000.00	10,000.00
641	Electric Sales	1,451,722.00	1,589,530.00	1,674,601.00	1,618,652.00	1,653,841.00	2,160,000.00	2,199,870.42
646	Timber Sales	20,975.00	0.00	0.00	0.00	0.00	0.00	0.00
647	Surplus Power Sales	70,133.00	44,342.00	41,456.00	24,254.00	38,945.00	35,000.00	35,000.00
648	Demand Charges	59,901.00	78,115.00	94,596.00	81,947.00	77,097.00	96,000.00	91,000.00
655	Penalties	13,575.00	17,348.00	15,178.00	16,268.00	16,256.00	17,000.00	17,000.00
665	Interest on Investments	87,303.00	74,150.00	72,379.00	72,191.00	45,868.00	25,000.00	25,000.00
673	Sale of Property	0.00	0.00	0.00	0.00	0.00	200,000.00	0.00
674	Developer Contributions	0.00	1,061.00	2,599.00	8,103.00	0.00	10,000.00	10,000.00
679	Plan Review/ Consulting Reimbursement	0.00	0.00	0.00	0.00	0.00	0.00	0.00
680	Transfers In From Other Funds	0.00	4,097.00	0.00	113,229.00	0.00	0.00	0.00
685	From Fund Equity - One Time	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	**1,727,976**	**1,834,383**	**1,951,862**	**1,974,187**	**2,853,278**	**2,711,285**	**2,421,155**
	OPERATING EXPENSES	(1,315,023)	(1,873,884)	(2,028,676)	(2,310,004)	(2,758,002)	(2,776,029)	(2,244,094)
	RETAINED EARNINGS	412,953	(39,501)	(76,814)	(335,817)	95,276	(64,744)	177,061

5.1 Electric Utility Customers

Table 5 presents the quantity of utility customers, based on the number of electric meters in each service class during recent years. Ninety-one percent of Norway's customers are residential. About 8% are commercial customers, 0.2% are small industrial, 0.2% are industrial and 0.3% are street lighting. Norway's customer base is very stable, exhibiting only minimal variation within the past five years. In Table 5, as well as Tables 6 through 8 we have included some projected data for the 2003-2004 budget year as well as for a study year.

5.2 Annual Electric Customer Revenues

Table 6 presents the annual energy revenues by customer class in recent years for the City of Norway. Residential customers represent the largest source of revenue for Norway, about 51% of the total customer revenues. Commercial customers provide about 38% of Norway's customer revenues, followed by industrial customers at approximately 9%. Small industrial and street lighting each represent about 1% of Norway's annual customer revenues.

The energy revenues presented in the table include the monthly service charge for each customer class. There is some variation in revenues from year to year, due perhaps to weather conditions. Note that the study year shows a significant increase in the percentage of revenues from residential customers. This situation will be discussed in subsequent sections of the report.

5.3 Annual Energy Sales

Table 7 presents the annual energy sales in kWh for each customer class. Residential customers represent the largest customer class, consuming approximately 56% of Norway's energy output. Commercial customers consume about 36% of the utility's output. Industrial customers represent about 7% of the total kWh distributed in 2001. Small industrial and street lighting each consume about 1% of the total energy output.

5.4 Annual Energy Sales Revenue per kWh

The data in Table 6 can be divided by the data in Table 7 to obtain energy sales revenue information on an average $/kWh basis as presented in Table 8. For 2001 the industrial revenues on an average $/kWh basis are the highest, followed by the small industrial, commercial, and street lighting revenues. Residential customers have the lowest $/kWh.

Table 5
Annual Electric Customers (Number of Meters)

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	Meters	% of Total	Meters	% of Total	Meters	% of Total	Meters	% of Total	Meters	% of Total	Meters	% of Total	Meters	% of Total
Residential	1,669	90.1%	1,720	89.4%	1,897	90.4%	1,976	90.8%	1,979	90.9%	2,077	91.0%	2,077	91.0%
Commercial	171	9.2%	189	9.8%	186	8.9%	186	8.5%	183	8.4%	192	8.4%	192	8.4%
Small Industrial	4	0.2%	4	0.2%	4	0.2%	4	0.2%	4	0.2%	4	0.2%	4	0.2%
Industrial	5	0.3%	6	0.3%	6	0.3%	5	0.2%	4	0.2%	4	0.2%	4	0.2%
Street Lighting	4	0.2%	4	0.2%	5	0.2%	5	0.2%	6	0.3%	6	0.3%	6	0.3%
Total	**1853**	**100.0%**	**1923**	**100.0%**	**2098**	**100.0%**	**2176**	**100.0%**	**2176**	**100.0%**	**2283**	**100.0%**	**2283**	**100.0%**

Table 6
Annual Electric Customer Revenues ($)

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	$	% of Total	$	% of Total	$	% of Total	$	% of Total	$	% of Total	$	% of Total	$	% of Total
Residential	973,000	54.5%	642,000	41.5%	758,594	45.3%	788,930	48.7%	840,000	51.0%	882,000	51.0%	1,265,561	54.8%
Commercial	643,905	36.0%	588,665	38.1%	623,453	37.2%	618,340	38.2%	623,538	37.9%	654,714	37.9%	810,823	35.1%
Small Industrial	17,388	1.0%	16,335	1.1%	16,835	1.0%	17,158	1.1%	17,462	1.1%	18,335	1.1%	18,250	0.8%
Industrial	133,000	7.4%	281,000	18.2%	258,056	15.4%	178,051	11.0%	148,000	9.0%	155,400	9.0%	196,237	8.5%
Street Lighting	19,000	1.1%	18,000	1.2%	17,666	1.1%	16,186	1.0%	17,000	1.0%	17,850	1.0%	17,850	0.8%
Total	**1,786,293**	**100.0%**	**1,546,000**	**100.0%**	**1,674,601**	**100.0%**	**1,618,652**	**100.0%**	**1,646,000**	**100.0%**	**1,728,299**	**100.0%**	**2,308,720**	**100.0%**

Table 7
Annual Electric Sales (kWh)

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	kWh	% of Total	kWh	% of Total	kWh	% of Total	kWh	% of Total	kWh	% of Total	kWh	% of Total	kWh	% of Total
Residential	16,155,000	63.5%	11,956,000	45.9%	13,264,000	49.9%	14,333,000	53.2%	15,162,000	55.8%	15,920,100	55.8%	15,920,100	55.8%
Commercial	5,901,080	23.2%	9,616,611	36.9%	9,645,948	36.3%	9,669,333	35.9%	9,686,765	35.6%	10,171,103	35.6%	10,171,103	35.6%
Small Industrial	138,920	0.5%	226,389	0.9%	227,079	0.9%	227,630	0.8%	232,235	0.9%	243,846	0.9%	243,846	0.9%
Industrial	2,857,000	11.2%	3,953,000	15.2%	3,149,000	11.9%	2,433,000	9.0%	1,804,000	6.6%	1,894,200	6.6%	1,894,200	6.6%
Street Lighting	371,000	1.5%	282,000	1.1%	286,000	1.1%	290,000	1.1%	294,000	1.1%	308,700	1.1%	308,700	1.1%
Total	**25,423,000**	**100.0%**	**26,034,000**	**100.0%**	**26,572,027**	**100.0%**	**26,952,963**	**100.0%**	**27,179,000**	**100.0%**	**28,537,949**	**100.0%**	**28,537,949**	**100.0%**

Note: The 1999 and 2000 data was estimated from the 1998 and 2001 actual data.

Table 8
Annual Electric Revenue ($/kWh)

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	$/kWh	% of Avg.	$/kWh	% of Avg.	$/kWh	% of Avg.	$/kWh	% of Avg.	$/kWh	% of Avg.	$/kWh	% of Avg.	$/kWh	% of Avg.
Residential	0.06023	85.7%	0.05370	90.4%	0.05719	90.8%	0.05504	91.7%	0.05540	91.5%	0.05540	91.5%	0.07949	98.3%
Commercial	0.10912	155.3%	0.06121	103.1%	0.06463	102.6%	0.06395	106.5%	0.06437	106.3%	0.06437	106.3%	0.07972	98.5%
Small Industrial	0.12517	178.1%	0.07215	121.5%	0.07414	117.6%	0.07538	125.5%	0.07519	124.2%	0.07519	124.2%	0.07484	92.5%
Industrial	0.04655	66.3%	0.07109	119.7%	0.08195	130.0%	0.07318	121.9%	0.08204	135.5%	0.08204	135.5%	0.10360	128.1%
Street Lighting	0.05121	72.9%	0.06383	107.5%	0.06177	98.0%	0.05581	92.9%	0.05782	95.5%	0.05782	95.5%	0.05782	71.5%
Utility Average	**0.07026**		**0.05938**		**0.06302**		**0.06005**		**0.06056**		**0.06056**		**0.08090**	

5.5 Meters, Revenues and kWh Sales

The data from Tables 5, 6 and 7 can be presented in the form of pie charts to provide a better understanding of the relationship between the number of meters, revenues and kWh sales for each customer class. Chart 2 shows the percentage of total meters in each customer class for 2001. About 90.9% of Norway's customers are residential, followed by about 8.4% commercial, 0.3% street lighting, 0.2% small industrial and 0.2% for industrial. Although 90.9% of Norway's' standard meters are installed on residential properties, these customers represent about 51% of the customer revenues as shown in Chart 3 and 55.8% of total kWh sales shown in Chart 4. The residential customers are using 55.8% of the electric energy but are providing only 51% of the utility revenues. This represents a significant imbalance in the electric rate structure. The residential customers appear to be paying a quite a bit less than they should for the energy they consume. The City of Norway has just the opposite situation for commercial customers. Commercial customers consume only 35.6% of the energy but provide 37.9% of the revenues. The industrial customers also appear to be paying more than their share for the electric energy they consume. The comparison between Charts 3 and 4 suggests that a rate increase for residential customers might be appropriate.

Chart 2 – 2001 Customer Meters

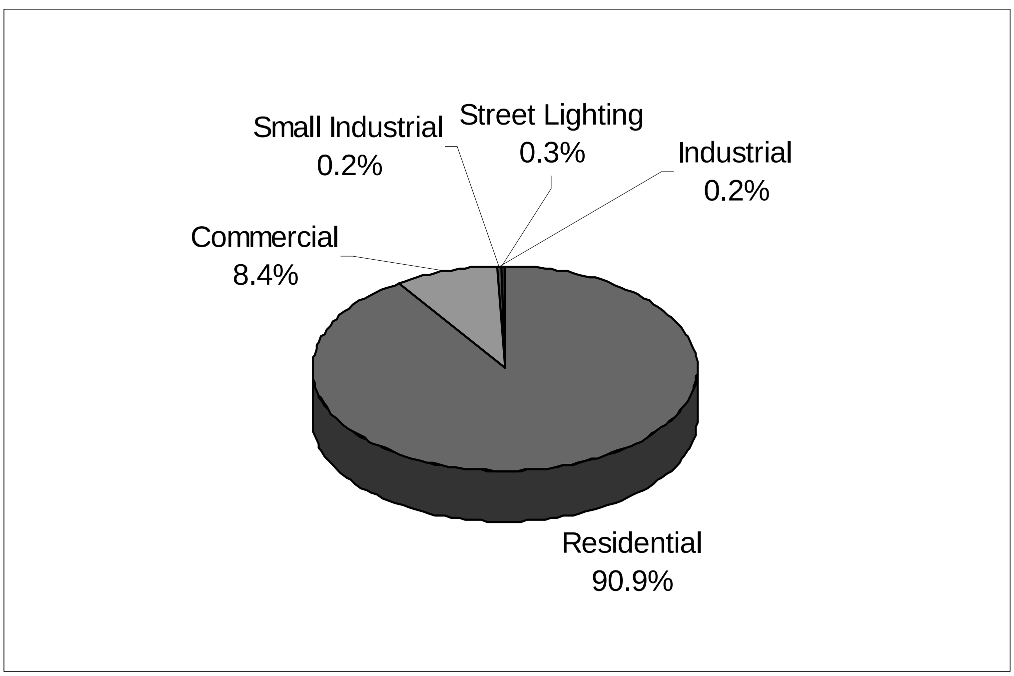
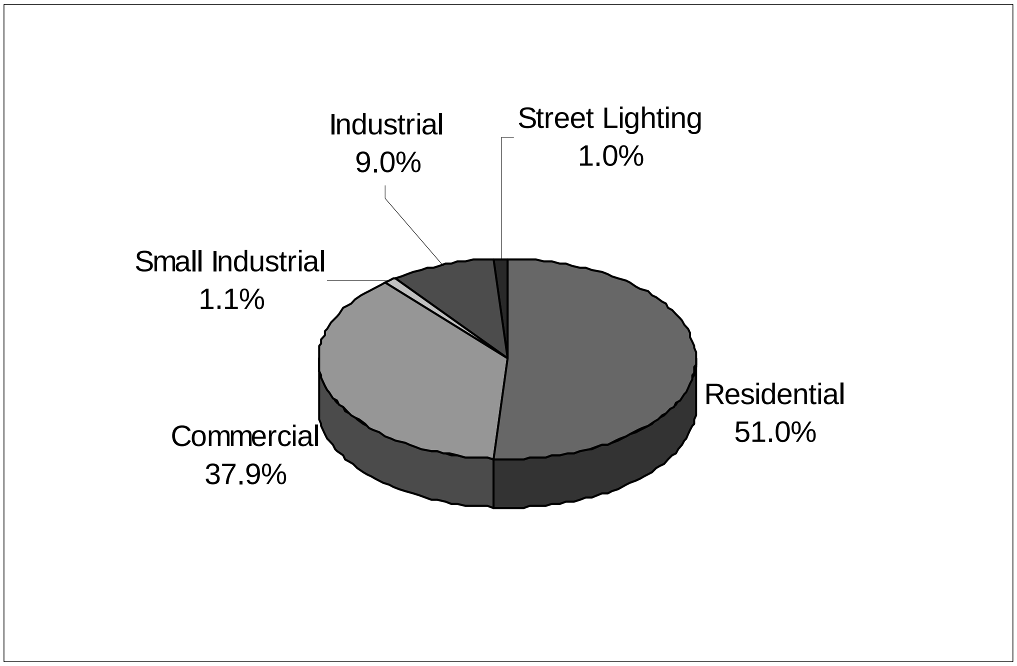


Chart 3 – Customer Electric Revenues ($)



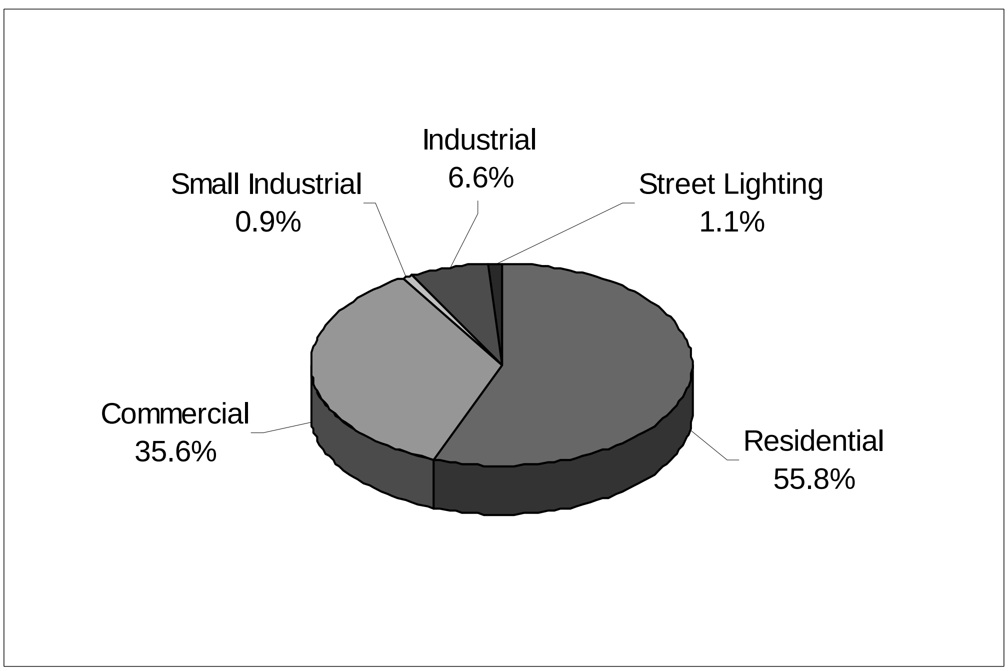


Chart 4 – Customer Electric Sales (kWh)

6.0 Cost of Service Rates

Electric rates are generally based on many factors. The cost of service is one of the most important considerations in establishing rates. This section will focus on cost of service as a rate-making tool. Subsequent sections will discuss other factors that enter into rate development.

The American Public Power Association (APPA) offers a methodology to establish cost of service rates for municipal utilities. We have applied this methodology to the City of Norway, with some minor modifications to accommodate local situations specific to Norway. APPA also offers a methodology for unbundling retail electric rates. Although complete unbundling may not be appropriate under the present electric regulatory climate, we have incorporated many of the APPA unbundling concepts. These will be discussed in detail in subsequent pages of this report.

There are three major steps in the APPA cost of service methodology. These steps are as follows:

1. Functionalize the utility revenue requirements according to cost type
2. Classify the utility revenue requirements according to the services provided
3. Allocate the utility revenue requirements among customer classes

Each of the APPA steps are described below.

6.1 Functionalization of Revenue Requirements

Cost of service rates are based on the revenue requirements of the utility. An electric utility has a set of costs that must be met in order to stay in business each year. The utility must have enough revenue each year to meet these costs. Utility costs vary from year to year but are generally quite predictable. A look at the costs and revenues of past years probably offers the best indication of utility requirements in future years.

For cost of service purposes, utility costs are typically broken down, or functionalized into the following cost functions:

1. Production or Purchased Power
2. Transmission
3. Distribution
4. Customer Service
5. Administration
6. Revenue

The first four items should be relatively self-explanatory. Administration refers largely to general office functions and overhead. The revenue function refers to other operating and non-operating revenue sources generally not part of the utility's primary purpose of providing reliable electric service to its customers. The revenue components can be positive or negative. For example, revenues from the sale of surplus materials and equipment would represent a positive revenue component. The transfer of utility revenues to the city general fund would be a negative revenue component.

The annual utility and city financial reports provide a good start to functionalizing the utility's operating expenses. The financial data was presented earlier in Table 3A. In future pages we will make adjustments to the financial data to further functionalize these expenses but first we should review the other two major steps in the APPA cost of service methodology.

6.2 Classification of Revenue Requirements

After the utility revenue requirements have been separated by function, they can be classified according to cost component. The typical utility cost components are as follows:

1. Energy
2. Demand
3. Customer
4. Revenue
5. Direct

Energy costs are associated with the supply of energy to meet the electric requirements of the utility customers. These costs vary with kWh energy consumption. Demand costs are associated with the peak demand of each customer and overall peak demand of the utility. The peak occurs when utility customers are using the highest amounts of energy. Peak electric demand periods typically take place during hot summer weather when customers are making heavy use of air conditioning or during exceptionally cold winter weather when electric heat is operating.

Customer costs are associated with billing functions and serving the utility's customers. Customer costs typically vary with the number of customers that a utility serves. Revenue costs were described previously and are associated with the sale of surplus equipment, financial transfers to the city general fund or other sources of income and disbursements not generally associated with the utility's core function of providing electric service. Direct costs are costs clearly related to a specific customer or class of customers. Special services to a key industrial customer or to a specific group of rural customers are examples of direct costs. Street lighting might also be considered a direct cost.

The functionalization and classification processes are typically straightforward with the possible exception of general and administrative costs. The utility financial data presented previously in Table 3A has many entries devoted to general expenses. These expenses should be broken down into the classifications described above. Tables 9 and 10 demonstrate the classification of general expenses. Table 9 repeats the portions of Table 3 that are classified as general expenses. In Table 10, allocation factors are applied to the total yearly general expenses from Table 9. The allocation factors are somewhat arbitrary. In Table 10, we have assumed that 30% of the utility general expenses can be allocated to each of the functions represented by power generation (demand), distribution system and customer service. Energy is allocated 5%, revenue 4% and street lighting 1%.

Tables 11 and 12 demonstrate the classification of generation plant expenses following the format used earlier for Tables 9 and 10. Table 11 repeats the portions of Table 3 that are classified as generation plant expenses. In Table 12, allocation factors are applied to the total yearly generation plant expenses from Table 11. Again, the allocation factors are somewhat arbitrary. In Table 12, we have assumed that 40% of the utility generation plant expenses can be allocated to power (demand) while 60% can be allocated to energy.

The rest of the cost classification process is accomplished in Table 13. For Norway, we used six utility functions as follows:

1. Customer Service
2. Street Lighting
3. Power (kW Demand)
4. Energy (kWh Energy)
5. Distribution System (Poles, Wires, Underground, Substations)
6. Revenue (non-utility related functions)

Table 13 is a reorganization of the city financial statements for the electric utility as presented earlier in Table 3A, with adjustments made in Tables 9 though 11. Note that each of the functions presented in Table 13 has a general expense item. The general expense items for each function were developed previously in Tables 9 and 10. Recall that we used Tables 9 and 10 to allocate the large general expense category to the various utility functions.

Table 9
General Expenses ($)

Acct. #	Year / General Expenses	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
		$	$	$	$	$	$	$
702	Salaries - Full Time	433,560	357,642	343,677	331,936	312,377	422,665	422,665
703	Salaries - Part Time	0	0	0	3,864	22,196	8,438	8,438
704	Salaries - Overtime	0	49,520	52,297	59,219	69,650	63,430	63,430
705	Employee Separation	0	6,615	0	14,500	0	0	0
706	Sick Time Buyback	0	0	0	0	0	0	0
707	Longevity pay	5,675	4,875	4,925	4,725	4,350	4,800	4,800
708	COLA Adjustment	0	0	0	0	1,205	0	0
709	Shift Differential - Hydro	0	0	0	0	0	0	0
712	VEBA Contribution	0	0	0	0	5,450	5,430	5,430
715	Employer - FICA	32,693	32,122	30,489	33,155	31,875	38,250	38,250
716	Group Insurance	72,875	82,123	103,086	108,512	123,048	195,983	195,983
717	Self Insured Retention	0	0	0	0	3,204	9,000	9,000
718	Employer - MERS	3,841	25,229	36,306	52,036	44,633	68,250	68,250
719	Unemployment Compensation	9,981	8,749	3,976	3,045	1,429	4,460	4,460
720	Training/Membership/Travel/Education	0	3,570	3,561	4,237	5,007	13,500	13,500
740	Supplies (Operating & Office)	28,155	10,775	12,970	9,259	4,855	7,000	7,000
745	Printing/Postage/Stationary/Publications	0	5,852	6,245	6,819	9,624	7,000	7,000
750	Uniform/ Cleaning Expense	1,036	3,061	2,499	2,675	3,524	3,600	3,600
751	Gas & Oil	3,712	3,811	4,085	4,252	4,021	5,500	5,500
753	Banners & Decorations	0	8,620	1,331	1,486	309	0	0
819	Professional Services	18,958	13,599	5,208	86,260	50,190	31,500	31,500
861	Maintenance - Equip/Buildings	15,346	25,529	19,590	36,313	30,177	20,000	20,000
903	Computer Expense	4,109	3,488	5,130	1,493	385	1,000	1,000
914	Insurance - Liab./Prop./Worker's Comp.	45,487	65,240	58,391	32,536	38,103	50,330	50,330
920	Telephone	0	2,797	3,612	3,993	4,546	4,200	4,200
922	Heating Fuel (Michcon)	0	2,481	1,738	2,492	406	2,500	2,500
925	Disposal Expense	0	7,425	0	4,636	9,964	3,000	3,000
942	Rental/Lease	0	9,412	9,406	9,400	9,700	11,250	11,250
955	Property Taxes	2,423	2,642	2,856	3,096	3,269	3,500	3,500
956	Misc. Expense	7,649	2,151	0	0	0	0	0
	Total	**685,500**	**737,328**	**711,378**	**819,939**	**793,497**	**984,586**	**984,586**

Table 10
General Expenses Allocated By Function ($)

	Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Utility Function	**Allocation Factor**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Power	30%	205,650	221,198	213,413	245,982	238,049	295,376	295,376
Energy	5%	34,275	36,866	35,569	40,997	39,675	49,229	49,229
Distribution System	30%	205,650	221,198	213,413	245,982	238,049	295,376	295,376
Customer Service	30%	205,650	221,198	213,413	245,982	238,049	295,376	295,376
Street Lighting	1%	6,855	7,373	7,114	8,199	7,935	9,846	9,846
Revenue	4%	27,420	29,493	28,455	32,798	31,740	39,383	39,383
Total	**100%**	**685,500**	**737,328**	**711,378**	**819,939**	**793,497**	**984,586**	**984,586**

Table 11
Generation Plant Expenses

	Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Acct. #	**Generation Plant Expenses**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
974	Bond Payment - Principal	0	110,000	110,000	115,000	125,000	165,000	165,000
993	Bond Issue Costs (Discounts)	21,184	1,184	21,184	21,184	21,245	21,245	21,245
995	Interest expense	109,004	103,905	99,358	94,499	92,822	137,982	137,982
972	Capital Improvements - Hydro Plant	0	262,929	274,377	357,103	261,976	634,500	0
972-021	Dam Stabilization Project	0	0	0	0	14,552	0	0
972-022	Hydro Stabilization Project	0	0	0	0	65,150	0	0
647	Surplus Power Sales	(70,133)	(44,342)	(41,456)	(24,254)	(38,945)	(35,000)	(35,000)
998	To Equipment Replacement Fund	0	0	110,457	0	0	0	54,000
999	To Capital Projects Fund	100,000	0	35,000	35,000	35,000	35,000	274,781
	Totals	160,055	433,676	608,920	598,532	576,800	958,727	618,008

Table 12
Generation Plant Expenses Allocated by Function

	Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Utility Function	**Allocation Factor**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Power	40%	64,022	173,470	243,568	239,413	230,720	383,491	247,203
Energy	60%	96,033	260,206	365,352	359,119	346,080	575,236	370,805
Distribution System	0%	0	0	0	0	0	0	0
Customer Service	0%	0	0	0	0	0	0	0
Street Lighting	0%	0	0	0	0	0	0	0
Revenue	0%	0	0	0	0	0	0	0
Total	100%	160,055	433,676	608,920	598,532	576,800	958,727	618,008

Table 13
Annual Electric Utility Expenses By Function ($)

Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Customer Service	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Meter Expense	473	1,687	38	5,007	2,328	5,000	5,000
General Expenses	205,650	221,198	213,413	245,982	238,049	295,376	295,376
Generation Plant Expenses	0	0	0	0	0	0	0
Subtotal	**206,123**	**222,885**	**213,451**	**250,989**	**240,377**	**300,376**	**300,376**
Street Lighting							
Street Lighting	4,809	5,626	1,342	4,334	5,417	3,000	3,000
General Expenses	6,855	7,373	7,114	8,199	7,935	9,846	9,846
Generation Plant Expenses	0	0	0	0	0	0	0
Subtotal	**11,664**	**12,999**	**8,456**	**12,533**	**13,352**	**12,846**	**12,846**
Power (Demand)							
Purchased Power	91,171	113,174	95,309	108,921	111,613	160,000	135,000
General Expenses	205,650	221,198	213,413	245,982	238,049	295,376	295,376
Generation Plant Expenses	64,022	173,470	243,568	239,413	230,720	383,491	247,203
Subtotal	**360,843**	**507,842**	**552,290**	**594,316**	**580,382**	**838,867**	**677,579**
Energy							
Energy Purchases - Energy	169,317	210,179	177,002	202,282	207,280	255,000	210,000
General Expenses	34,275	36,866	35,569	40,997	39,675	49,229	49,229
Generation Plant Expenses	96,033	260,206	365,352	359,119	346,080	575,236	370,805
Subtotal	**299,625**	**507,251**	**577,922**	**602,398**	**593,035**	**879,466**	**630,034**
Distribution System							
Transmission/Distribution Expense	62,316	37,951	34,880	42,874	31,276	50,000	50,000
Toll Charges	11,292	14,148	16,168	19,144	12,888	23,500	23,500
New Vehicles $ Equip.	0	0	0	0	39,298	60,000	0
Capital Improvements - System	30,521	96,728	66,982	105,352	79,548	51,000	0
General Expenses	205,650	221,198	213,413	245,982	238,049	295,376	295,376
Generation Plant Expenses	0	0	0	0	0	0	0
Subtotal	**309,779**	**370,025**	**331,443**	**413,352**	**401,059**	**479,876**	**368,876**
Revenue							
To General Fund	29,436	124,045	125,202	129,365	859,112	190,216	180,000
To Cable TV Fund - One Time	0	55,000	0	250,000	0	0	0
To Equipment Replacement Fund	0	0	110,457	0	0	0	54,000
To General Fund - One Time	0	0	150,000	0	0	0	0
To Capital Projects Fund	100,000	0	35,000	35,000	35,000	35,000	274,781
Retirees Insurance Reimbursement	0	15,788	21,813	19,757	20,023	28,285	28,285
Misc. Revenues	(11,470)	(1,480)	(7,647)	(1,858)	(870)	(130,000)	(5,000)
Line Installation Costs	(12,897)	(8,472)	(21,593)	(17,928)	(13,612)	(10,000)	(10,000)
Timber Sales	(20,975)	0	0	0	0	0	0
Penalties	(13,575)	(17,348)	(15,178)	(16,268)	(16,256)	(17,000)	(17,000)
Interest on Investments	(87,303)	(74,150)	(72,379)	(72,191)	(45,868)	(25,000)	(25,000)
Sale of Property	0	0	0	0	0	(200,000)	0
Developer Contributions	0	(1,061)	(2,599)	(8,103)	0	(10,000)	(10,000)
Plan Review/ Consulting Reimbursement	0	0	0	0	0	0	0
Transfers In From Other Funds	0	(4,097)	0	(113,229)	0	0	0
From Fund Equity - One Time	0	0	0	0	0	0	0
General Expenses	27,420	29,493	28,455	32,798	31,740	39,383	39,383
Generation Plant Expenses	0	0	0	0	0	0	0
Property Acquisition	0	0	0	0	0	0	0
Subtotal	**10,636**	**117,718**	**351,531**	**237,343**	**869,269**	**(99,116)**	**509,450**
Grand Total	**1,198,670**	**1,738,722**	**2,035,094**	**2,110,930**	**2,697,474**	**2,412,314**	**2,499,160**

In Table 13, the power and energy cost functions vary somewhat with the weather and with economic development from year to year but show a generally increasing trend. Colder weather during any one particular year will cause people to use electric heat more, increasing the wholesale energy costs to the utility. Unusually warm weather will cause utility customers to use more air conditioning, again boosting the utility wholesale energy costs for that year. The distribution function costs also vary from year to year, primarily due to expenditures for maintenance and capital improvements. The revenue costs vary tremendously from year to year. In 2001, a large transfer was made to the city general fund. During other years, inconsistencies in transfers to other city funds or revenues from non-core utility activities have resulted in the variations from year to year.

6.3 Allocation of Revenue Requirements to Customer Classes

Now that we have accomplished the functionalization of utility revenue requirements by cost function and the classification by service type, we must allocate these costs fairly to the utility customer classes to determine the cost of serving each customer class. The City of Norway has five primary customer classes as follows:

1. Residential
2. Commercial
3. Small Industrial
4. Industrial
5. Street Lighting

Customer service costs vary with the number of customers, or meters, that a utility supplies. Typically, some types of customers require more customer service attention than others. Three phase customers may have higher metering costs or may have more questions regarding their bills, service connection or power quality. For these and other reasons, it is customary to apply weighting factors to the raw quantity of customer meters in each customer class. Table 14 illustrates the customer service weighting factor process for Norway. Table 14 is a modification of Table 5, presented previously. Residential customers are typically assigned a weighting factor of one. We have assigned a weighting factor of three to the commercial customers and small industrial customers. The industrial customers receive a weighting factor of five. Street lighting customers have been assigned a weighting factor of 0.5.

The weighting factors are used to adjust the quantity of meters in each customer class and the overall total for the utility. The weighted quantity of meters in each customer class can be divided by the total number of utility meters to obtain an allocation factor. This allocation factor, expressed as a percentage of the total meters, will be used later to fairly allocate the customer service costs to each class of utility customers.

Table 14
Customer Metering Allocation Factors

Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Residential							
Number of Meters	1669	1720	1897	1976	1979	2077	2077
Weighting Factor	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Weighted Meters	1,669.0	1,720.0	1,897.0	1,976.0	1,979.0	2,077.0	2,077.0
Percent of Weighted Total	75.6%	74.2%	76.3%	77.1%	77.6%	77.6%	77.6%
Commercial							
Number of Meters	171	189	186	186	183	192	192
Weighting Factor	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Weighted Meters	513.0	567.0	558.0	558.0	549.0	576.0	576.0
Percent of Weighted Total	23.2%	24.5%	22.4%	21.8%	21.5%	21.5%	21.5%
Small Industrial							
Number of Meters	4	4	4	4	4	4	4
Weighting Factor	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Weighted Meters	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Percent of Weighted Total	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%
Industrial							
Number of Meters	5	6	6	5	4	4	4
Weighting Factor	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Weighted Meters	25.0	30.0	30.0	25.0	20.0	20.0	20.0
Percent of Weighted Total	1.1%	1.3%	1.2%	1.0%	0.8%	0.7%	0.7%
Street Lighting							
Number of Meters	4	4	5	5	6	6	6
Weighting Factor	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Weighted Meters	2.0	2.0	2.5	2.5	3.0	3.0	3.0
Percent of Weighted Total	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Totals							
Number of Meters	1,853	1,923	2,098	2,176	2,176	2,283	2,283
Weighted Meters	2,209.0	2,319.0	2,487.5	2,561.5	2,551.0	2,676.0	2,676.0

Allocation factors for energy and demand are presented in Table 15. Energy costs are easy to apply toward cost of service rate-making since they are largely associated with purchased energy. These costs can be allocated to the individual customer classes on a per kWh basis as demonstrated in the upper portion of Table 15. Note that the top section of Table 15 is a restatement of Table 7. In Table 7, we presented the annual electric kWh sales obtained from utility historical data, along with the percentage of total utility annual energy used by each customer class during the year. The percentages for kWh sales presented in the upper section of Table 15 will be used later in the analysis to allocate the cost of purchased energy to Norway's various customer classes.

Demand costs are not so easily allocated. Demand costs represent kW load and it is not practical to meter for residential and commercial customers. To allocate demand-related costs, certain assumptions must be made with regard to average load factors for residential and commercial customers. Load factor is a measure of how effectively a utility customer or customer group uses the electric distribution system. Load factor is expressed as a percentage representing the energy a customer actually used during the year compared to how much they could have possibly consumed if the customer one-time peak demand had lasted throughout the entire year instead of just occurring once. Load factor is calculated as follows:

$$\frac{\text{(Annual customer actual kWh energy use)}}{\text{(Peak customer kW demand) X (8760 hours per year)}}$$

A customer having a high load factor makes effective use of the utility distribution system because the customer's electric equipment runs near its peak consumption rate for most of the year. Convenience stores generally have high load factors because they are open for business on a 24-hour basis. The refrigerated coolers, lighting, heating or air conditioning equipment are always running. A grain elevator will typically have a very low load factor since the large electric motors for conveying and grain drying are operated only on an intermittent basis.

The central section of Table 15 shows the allocation of system peak demand by customer class. The lower section of the table shows the load factors that we assumed in the allocation process. Similar to the energy allocation percentages in the upper section of Table 15, the demand allocation percentages will be used later in the report to allocate the utility demand costs to the various customer groups to determine the cost of serving each customer group. The demand costs can then be combined with the energy costs and billed as a blended $/kWh rate for residential and commercial customers. For industrial customers, kW demand is typically metered and billed separately from kWh energy, making it much easier to allocate costs.

Table 15
Customer Energy (kWh) and Demand (kW) Allocation Factors

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
Energy	**kWh**	**% of Total**	**kWh**	**% of Total**	**kWh**	**% of Total**	**kWh**	**% of Total**	**kWh**	**% of Total**	**kWh**	**% of Total**	**kWh**	**% of Total**
Residential	16,155,000	63.5%	11,956,000	45.9%	13,264,000	49.9%	14,333,000	53.2%	15,162,000	55.8%	15,920,100	55.8%	15,920,100	55.8%
Commercial	5,901,080	23.2%	9,616,611	36.9%	9,645,948	36.3%	9,669,333	35.9%	9,686,765	35.6%	10,171,103	35.6%	10,171,103	35.6%
Small Industrial	138,920	0.55%	226,389	0.87%	227,079	0.85%	227,630	0.84%	232,235	0.85%	243,846	0.85%	243,846	0.85%
Industrial	2,857,000	11.2%	3,953,000	15.2%	3,149,000	11.9%	2,433,000	9.0%	1,804,000	6.6%	1,894,200	6.6%	1,894,200	6.6%
Street Lighting	371,000	1.5%	282,000	1.1%	286,000	1.1%	290,000	1.1%	294,000	1.1%	308,700	1.1%	308,700	1.1%
Total	**25,423,000**	**100.00%**	**26,034,000**	**100.00%**	**26,572,027**	**100.00%**	**26,952,963**	**100.00%**	**27,179,000**	**100%**	**28,537,949**	**100.00%**	**28,537,949**	**100%**
Demand	**kW**	**% of Total**	**kW**	**% of Total**	**kW**	**% of Total**	**kW**	**% of Total**	**kW**	**% of Total**	**kW**	**% of Total**	**kW**	**% of Total**
Residential	3,286	62.0%	2,498	45.0%	2,793	49.0%	3,009	51.0%	3,146	52.0%	3,172	52.0%	3,172	52.0%
Commercial	1,208	22.8%	2,015	36.3%	2,069	36.3%	2,142	36.3%	2,257	37.3%	2,275	37.3%	2,275	37.3%
Small Industrial	42	0.8%	67	1.2%	68	1.2%	71	1.2%	73	1.2%	61	1.0%	61	1.0%
Industrial	657	12.4%	888	16.0%	684	12.0%	590	10.0%	484	8.0%	500	8.2%	500	8.2%
Street Lighting	106	2.0%	83	1.5%	86	1.5%	89	1.5%	91	1.5%	92	1.5%	92	1.5%
Total	**5,300**	**100.0%**	**5,550**	**100.0%**	**5,700**	**100.0%**	**5,900**	**100.0%**	**6,050**	**100.0%**	**6,100**	**100.0%**	**6,100**	**100.0%**
Load Factor	**Load Factor**		**Load Factor**		**Load Factor**		**Load Factor**		**Load Factor**		**Load Factor**		**Load Factor**	
Residential	56%		55%		54%		54%		55%		57%		57%	
Commercial	56%		54%		53%		52%		49%		51%		51%	
Small Industrial	37%		39%		38%		37%		37%		46%		46%	
Industrial	50%		51%		53%		47%		43%		43%		43%	
Street Lighting	40%		39%		38%		37%		37%		39%		39%	
System Load Factor	55%		54%		53%		52%		51%		53%		53%	

6.4 Residential Cost of Service Rates

Residential cost of service rates are presented in Table 16. The table identifies the cost of service rates for customer service, street lighting, demand, energy, distribution and revenue. Lets start by taking a closer look at customer service, typically represented by a monthly customer charge. The top row of the table under Monthly Customer Charge (Customer Service) shows the total customer service expense for the entire utility during each of the past five years. This customer service expense was developed previously in Table 13. The total customer service expense is multiplied by the residential weighted metering allocation factor taken from Table 14 to obtain the customer service cost allocated to the residential customer class. This residential customer service cost can be divided by the number of residential meters and then by 12 (for 12 months in each year) to obtain the monthly cost of service for residential customer service.

The present customer service charge is also shown in the table for comparison. Note that the present monthly service charge is far lower than the cost of service charge calculated in the table. Recall that the customer service cost in Table 13 is primarily a function of the general expenses and how we chose to allocate these costs to the purchased power, energy, distribution and customer service cost categories. A different allocation would increase or decrease the cost of service rate for the monthly customer charge.

Now lets look at street lighting. Much like customer service, the total street lighting cost is again taken from Table 13. The street lighting cost can be divided by the total number of meters and by 12 (for 12 months in each year) to obtain a monthly cost of service rate for street lighting. Note that this street lighting cost represents only street light maintenance and a small fraction of the utility’s general and generation plant costs allocated somewhat arbitrarily to street lighting. The electric energy used to power the streetlights is sold by the utility to the city, represented by one of the city customer accounts. The cost of this energy is presumably covered by property taxes and other fees collected by the city. The electric utility bill does not presently have a line item for street lighting. An argument could be made that street lighting should be covered under the monthly customer service charge. Every utility customer would pay the same rate for street lighting as part of his or her monthly charge. As the utility regulatory climate moves in the direction of increasing competition and customer choice it may make sense for Norway to unbundle the electric rates and add a separate line item for street lighting on the monthly customer bill.

Electric demand is the focus of the next section in Table 16. Demand is one of the most significant components of the residential cost of service rates. The costs for and generated power were developed previously in Table 13. Then in Table 15 we identified allocation factors, expressed in percent, for allocating the utility peak demand to the residential and other customer classes. Now in Table 16 we use the power costs from Table 13 and the demand allocation factors from Table 15 to allocate a portion of the total utility power costs to the residential customer class, thereby determining the utility's cost of service rate for residential customers. Similar to the customer service section of Table 16, in the power section we take the total utility power costs from Table 13 and multiply them by the residential demand allocation factor from Table 15 to obtain the residential power cost. We can divide this by the total kW demand allocated to residential customers and then again by 12 (for 12 months in each year) to obtain a monthly demand charge per kW for residential power.

It is not practical to install demand meters for residential customers. Typically, only the three-phase industrial customers have demand meters. The meters for residential customers only measure kWh energy and not kW demand. For residential customers, we must take the process in Table 16 one step further by dividing the residential power cost by the annual kWh energy used by residential customers. The kWh energy recorded each month by the meters mounted on Norway's residential properties offers the best way to allocate the power costs for residential customers.

This process can be repeated for the energy, distribution system and revenue costs that contribute to the cost of service for residential customers. The unbundled cost of service rates for street lighting, demand, energy, distribution and revenue can be summed to obtain a total residential blended energy rate. This in turn can be compared with the utility's present residential electric rate. Note that in Table 16 the calculated cost of service rate is generally higher than the actual rate presently charged by the City of Norway. In 1997, the utility made a very modest transfer to the city general fund and made only limited capital improvements to the generating plant and electric distribution system. During 1997, the residential electric rates more than covered the cost of serving the residential customers. In 1998 and subsequent years, the utility made significant contributions to other city funds and increased the level of capital spending. This resulted in increased utility costs and the electric rate no longer kept up with the cost of service.

Table 16
Residential Cost of Service Rates

Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Monthly Customer Charge (Customer Service)							
Total Customer Service ($)	206,123.00	222,885.40	213,451.40	250,988.70	240,377.10	300,375.80	300,375.80
Res. Weighted Metering Allocation Factor	75.6%	74.2%	76.3%	77.1%	77.6%	77.6%	77.6%
Res. Customer Service ($)	155,735.30	165,313.88	162,780.83	193,618.45	186,478.35	233,139.21	233,139.21
Res. Meters	1669	1720	1897	1976	1979	2077	2077
Res. Monthly Customer Service Charge ($)	7.78	8.01	7.15	8.17	7.85	9.35	9.35
Present Res. Customer Service Charge ($)	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Street Lighting							
Total Street Lighting ($)	11,664.00	12,999.28	8,455.78	12,533.39	13,351.97	12,845.86	12,845.86
Total Utility Meters	1,853	1,923	2,098	2,176	2,176	2,283	2,283
Monthly Street Lighting Charge	0.52	0.56	0.34	0.48	0.51	0.47	0.47
Present Street Lighting Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand							
Total Power ($)	360,842.80	507,842.35	552,289.90	594,315.55	580,381.65	838,866.60	665,136.28
Res. Total Demand kW Allocation Factor	62.0%	45.0%	49.0%	51.0%	52.0%	52.0%	52.0%
Res. Power ($)	223,722.54	228,529.06	270,622.05	303,100.93	301,798.46	436,210.63	345,870.87
Res. Demand (kW)	3,286	2,498	2,793	3,009	3,146	3,172	3,172
Res. Demand Rate ($/kW-Month)	5.67	7.63	8.07	8.39	7.99	11.46	9.09
Res. Total kWh	16,155,000	11,956,000	13,264,000	14,333,000	15,162,000	15,920,100	15,920,100
Res. Demand Rate ($/kWh)	0.01385	0.01911	0.02040	0.02115	0.01990	0.02740	0.02173
Energy							
Total Energy ($)	299,625.20	507,251.45	577,922.40	602,398.10	593,035.30	879,465.50	611,370.03
Res. Energy Allocation Factor	63.5%	45.9%	49.9%	53.2%	55.8%	55.8%	55.8%
Res. Energy ($)	190,396.30	232,953.00	288,482.42	320,342.22	330,828.99	490,616.15	341,057.16
Res. kWh	16,155,000	11,956,000	13,264,000	14,333,000	15,162,000	15,920,100	15,920,100
Res. Energy Rate ($/kWh)	0.01179	0.01948	0.02175	0.02235	0.02182	0.03082	0.02142
Distribution							
Total Distribution System ($)	309,779.00	370,025.40	331,443.40	413,351.70	401,059.10	479,875.80	368,875.80
Res. Energy Allocation Factor	63.5%	45.9%	49.9%	53.2%	55.8%	55.8%	55.8%
Res. Distribution System ($)	196,848.51	169,932.54	165,447.12	219,811.45	223,733.69	267,702.16	205,780.02
Res. kWh	16,155,000	11,956,000	13,264,000	14,333,000	15,162,000	15,920,100	15,920,100
Res. Distribution Rate ($/kWh)	0.01218	0.01421	0.01247	0.01534	0.01476	0.01682	0.01293
Revenue							
Total Revenue ($)	10,636.00	117,718.12	351,531.12	237,342.56	869,268.88	-99,115.56	478,342.65
Res. Energy Allocation Factor	63.5%	45.9%	49.9%	53.2%	55.8%	55.8%	55.8%
Res. Revenue ($)	6,758.63	54,061.53	175,474.34	126,213.62	484,927.88	-55,292.33	266,846.89
Res. kWh	16,155,000	11,956,000	13,264,000	14,333,000	15,162,000	15,920,100	15,920,100
Res. Revenue Rate ($/kWh)	0.00042	0.00452	0.01323	0.00881	0.03198	-0.00347	0.01676
Total Res. Blended Energy Rate ($/kWh)	0.03824	0.05733	0.06785	0.06764	0.08846	0.07156	0.07284
Present Res. Energy Rate ($/kWh)	0.05500	0.05500	0.05500	0.05500	0.05500	0.05500	0.05500

6.5 Commercial Cost of Service Rates

Commercial cost of service rates are presented in Table 17. Table 17 follows the same format presented for residential cost of service in Table 16. Similar to the residential customer class, the present monthly commercial service charge is significantly higher than the cost of service charge calculated in the table. Recall that the customer service cost in Table 13 is primarily a function of the general expenses and how we chose to allocate these costs to the demand, energy, distribution and customer service cost categories. A different allocation would increase or decrease the cost of service rate for the monthly customer charge for commercial customers.

The street lighting, demand, energy and distribution rate components were discussed at length in the previous paragraphs under residential cost of service. Note that the $/kW monthly demand cost of service rates calculated for residential customers in Table 16 are the same as the cost of service rates for commercial customers calculated in Table 17. This is because in both Tables 16 and 17 we are starting with a total utility cost and using kW allocation factors from Table 15 that are based on the percent of peak utility kW demand allocated to each customer class. We then divide the result by the actual demand kW for each customer class, also from Table 15, to obtain the $/kW cost of service rates. The total cost of purchased power, for example, multiplied by an allocation factor derived from kW and then divided by actual kW will provide the same $/kW cost of service rate for any of Norway's customer classes. This provides a check that the analysis has been accomplished correctly and that errors have not crept into the cost data or calculations.

For commercial customers the demand component is typically included in the energy portion of the monthly utility bill, similar to residential customers. For these customers, the demand cost is billed based on kWh energy used throughout the month rather than the peak kW demand recorded that month by a demand meter. To relate kW demand costs to kWh energy consumption, a load factor is assumed for each customer class. When the demand cost is divided by annual kWh, we obtain a different demand component cost of service rate for each customer class. This is because we have assumed a different relationship, or load factor in Table 15 between annual kWh energy consumption and the peak kW demand for the year.

The unbundled cost of service rates for street lighting, demand, energy, distribution and revenue can be summed to obtain a total commercial blended energy rate. This in turn can be compared with the utility's present electric rate. In Table 17 the calculated cost of service rate is generally higher than the actual rate presently charged by the City of Norway. In 1997 and 1998, the commercial electric rates adequately covered the cost of serving the commercial customers.

In 1999 and subsequent years, the utility made significant contributions to other city funds and increased the level of capital spending. This resulted in increased utility costs and the electric rate for commercial customers no longer kept up with the cost of service.

6.6 Small industrial Cost of Service Rates

Small industrial cost of service rates are presented in Table 18. Table 18 follows the same format presented for residential and commercial cost of service in Tables 16 and 17. Recall that the customer service cost in Table 13 is primarily a function of the general expenses and how we chose to allocate these costs to the demand, energy and distribution cost categories. A different allocation would increase or decrease the cost of service rate for the monthly customer charge for small industrial customers.

The street lighting, demand, energy and distribution rate components were discussed at length in the residential cost of service section above. The unbundled cost of service rates for street lighting, demand, energy, distribution and revenue can be summed to obtain a total small industrial blended energy rate. This in turn can be compared with the utility's present electric rate. In 1997 and 1998, the small industrial electric rates appear to be significantly higher than the cost of serving the small industrial customers. In 1999 and 2000, the rates seem to keep up with the cost of service but fall behind in the year 2001.

6.7 Industrial Cost of Service Rates

Industrial cost of service rates are presented in Table 19. Table 19 follows the same format presented in Tables 16, 17 and 18. Similar to the other customer classes, the present monthly service charge for industrial three-phase customers is significantly lower than the cost of service charge calculated in the table. Recall that the customer service cost in Table 13 is primarily a function of the general expenses and how we chose to allocate these costs to the demand, energy, distribution, customer service and revenue cost categories. A different allocation would increase or decrease the cost of service rate for the monthly customer charge for industrial customers. Likewise, in Table 14 we established weighting factors for customer metering charges. In the table, we assumed that an industrial customer, in general, requires five times more customer service effort on the part of the utility than a residential customer does. A different assumption in Table 14 will affect the customer service cost of service rate calculated in the top portion of Table 19.

Table 17
Commercial Cost of Service Rates

Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Monthly Customer Charge (Customer Service)							
Total Customer Service ($)	206,123.00	222,885.40	213,451.40	250,988.70	240,377.10	300,375.80	300,375.80
Com. Weighted Metering Allocation Factor	23.2%	24.5%	22.4%	21.8%	21.5%	21.5%	21.5%
Com. Customer Service ($)	47,868.31	54,495.91	47,881.76	54,675.66	51,731.49	64,654.88	64,654.88
Com. Meters	171	189	186	186	183	192	192
Com. Monthly Customer Service Charge ($)	23.33	24.03	21.45	24.50	23.56	28.06	28.06
Present Com. Customer Service Charge ($)	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Street Lighting							
Total Street Lighting ($)	11,664.00	12,999.28	8,455.78	12,533.39	13,351.97	12,845.86	12,845.86
Total Utility Meters	1,853	1,923	2,098	2,176	2,176	2,283	2,283
Monthly Street Lighting Charge	0.52	0.56	0.34	0.48	0.51	0.47	0.47
Present Street Lighting Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand							
Total Power ($)	360,842.80	507,842.35	552,289.90	594,315.55	580,381.65	838,866.60	665,136.28
Com. Total Demand kW Allocation Factor	22.8%	36.3%	36.3%	36.3%	37.3%	37.3%	37.3%
Com. Power ($)	82,272.16	184,346.77	200,481.23	215,736.54	216,482.36	312,897.24	248,095.83
Com. Demand (kW)	1,208	2,015	2,069	2,142	2,257	2,275	2,275
Com. Demand Rate ($/kW-Month)	5.67	7.63	8.07	8.39	7.99	11.46	9.09
Com. Total kWh	5,901,080	9,616,611	9,645,948	9,669,333	9,686,765	10,171,103	10,171,103
Com. Demand Rate ($/kWh)	0.01394	0.01917	0.02078	0.02231	0.02235	0.03076	0.02439
Energy							
Total Energy ($)	299,625.20	507,251.45	577,922.40	602,398.10	593,035.30	879,465.50	611,370.03
Com. Energy Allocation Factor	23.2%	36.9%	36.3%	35.9%	35.6%	35.6%	35.6%
Com. Energy ($)	69,547.74	187,371.89	209,792.40	216,109.37	211,361.48	313,446.99	217,896.09
Com. kWh	5,901,080	9,616,611	9,645,948	9,669,333	9,686,765	10,171,103	10,171,103
Com. Energy Rate ($/kWh)	0.01179	0.01948	0.02175	0.02235	0.02182	0.03082	0.02142
Distribution							
Total Distribution System ($)	309,779.00	370,025.40	331,443.40	413,351.70	401,059.10	479,875.80	368,875.80
Com. Energy Allocation Factor	23.2%	36.9%	36.3%	35.9%	35.6%	35.6%	35.6%
Com. Distribution System ($)	71,904.60	136,682.43	120,317.72	148,289.27	142,939.96	171,030.73	131,469.64
Com. kWh	5,901,080	9,616,611	9,645,948	9,669,333	9,686,765	10,171,103	10,171,103
Com. Distribution Rate ($/kWh)	0.01218	0.01421	0.01247	0.01534	0.01476	0.01682	0.01293
Revenue							
Total Revenue ($)	10,636.00	117,718.12	351,531.12	237,342.56	869,268.88	-99,115.56	478,342.65
Com. Energy Allocation Factor	23.2%	36.9%	36.3%	35.9%	35.6%	35.6%	35.6%
Com. Revenue ($)	2,468.78	43,483.50	127,609.79	85,146.27	309,812.85	-35,325.40	170,484.30
Com. kWh	5,901,080	9,616,611	9,645,948	9,669,333	9,686,765	10,171,103	10,171,103
Com. Revenue Rate ($/kWh)	0.00042	0.00452	0.01323	0.00881	0.03198	-0.00347	0.01676
Total Com. Blended Energy Rate ($/kWh)	0.03833	0.05739	0.06824	0.06880	0.09091	0.07492	0.07550
Present Com. Energy Rate ($/kWh)	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500

Table 18
Small Industrial Cost of Service Rates

Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Monthly Customer Charge (Customer Service)							
Total Customer Service ($)	206,123.00	222,885.40	213,451.40	250,988.70	240,377.10	300,375.80	300,375.80
Sm. Ind. Weighted Metering Allocation Factor	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.4%
Sm. Ind. Customer Service ($)	1,119.73	1,153.35	1,029.72	1,175.82	1,130.74	1,346.98	1,346.98
Sm. Ind. Meters	4	4	4	4	4	4	4
Sm. Ind. Monthly Customer Service Charge ($)	23.33	24.03	21.45	24.50	23.56	28.06	28.06
Present Sm. Ind. Customer Service Charge ($)	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Street Lighting							
Total Street Lighting ($)	11,664.00	12,999.28	8,455.78	12,533.39	13,351.97	12,845.86	12,845.86
Total Utility Meters	1,853	1,923	2,098	2,176	2,176	2,283	2,283
Monthly Street Lighting Charge	0.52	0.56	0.34	0.48	0.51	0.47	0.47
Present Street Lighting Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand							
Total Power ($)	360,842.80	507,842.35	552,289.90	594,315.55	580,381.65	838,866.60	665,136.28
Sm. Ind. Total Demand kW Allocation Factor	0.8%	1.2%	1.2%	1.2%	1.2%	1.0%	1.0%
Sm. Ind. Power ($)	2,886.74	6,094.11	6,627.48	7,131.79	6,964.58	8,388.67	6,651.36
Sm. Ind. Demand (kW)	42	67	68	71	73	61	61
Sm. Ind. Demand Rate ($/kW-Month)	5.67	7.63	8.07	8.39	7.99	11.46	9.09
Sm. Ind. Total kWh	138,920	226,389	227,079	227,630	232,235	243,846	243,846
Sm. Ind. Demand Rate ($/kWh)	0.02078	0.02692	0.02919	0.03133	0.02999	0.03440	0.02728
Energy							
Total Energy ($)	299,625.20	507,251.45	577,922.40	602,398.10	593,035.30	879,465.50	611,370.03
Sm. Ind. Energy Allocation Factor	0.55%	0.87%	0.85%	0.84%	0.85%	0.85%	0.85%
Sm. Ind. Energy ($)	1,637.25	4,411.01	4,938.80	5,087.53	5,067.28	7,514.70	5,223.93
Sm. Ind. kWh	138,920	226,389	227,079	227,630	232,235	243,846	243,846
Sm. Ind. Energy Rate ($/kWh)	0.01179	0.01948	0.02175	0.02235	0.02182	0.03082	0.02142
Distribution							
Total Distribution System ($)	309,779.00	370,025.40	331,443.40	413,351.70	401,059.10	479,875.80	368,875.80
Sm. Ind. Energy Allocation Factor	0.55%	0.87%	0.85%	0.84%	0.85%	0.85%	0.85%
Sm. Ind. Distribution System ($)	1,692.74	3,217.70	2,832.45	3,490.94	3,426.91	4,100.36	3,151.90
Sm. Ind. kWh	138,920	226,389	227,079	227,630	232,235	243,846	243,846
Sm. Ind. Distribution Rate ($/kWh)	0.01218	0.01421	0.01247	0.01534	0.01476	0.01682	0.01293
Revenue							
Total Revenue ($)	10,636.00	117,718.12	351,531.12	237,342.56	869,268.88	-99,115.56	478,342.65
Sm. Ind. Energy Allocation Factor	0.55%	0.87%	0.85%	0.84%	0.85%	0.85%	0.85%
Sm. Ind. Revenue ($)	58.12	1,023.66	3,004.11	2,004.47	7,427.60	-846.91	4,087.26
Sm. Ind. kWh	138,920	226,389	227,079	227,630	232,235	243,846	243,846
Sm. Ind. Revenue Rate ($/kWh)	0.00042	0.00452	0.01323	0.00881	0.03198	-0.00347	0.01676
Total Sm. Ind. Blended Energy Rate ($/kWh)	0.04517	0.06514	0.07664	0.07782	0.09855	0.07856	0.07839
Present Sm. Ind. Energy Rate 1st 1,000 kWh (	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500
Present Sm. Ind. Energy Rate 1,000 to 20,000	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500

The street lighting, demand, energy, distribution system and revenue cost components were discussed at length above in the sections on residential and commercial cost of service. Unlike the residential and commercial customers, all of the industrial customers have demand meters. The purchased power, or demand is not included in the $/kWh blended energy rate for industrial customers. Consequently, the present industrial $/kWh rates are quite a bit lower than those for residential and commercial customers.

In Table 19, we did not include the demand component in the total industrial blended energy rate near the bottom of the table. Instead, the total industrial rate represents the sum of only the street lighting, energy, distribution system and revenue rate components. This is a departure from the methodology used in Tables 16, 17 and 18 for residential, commercial and small industrial rates. Notice that between 1997 and 2000, the calculated total industrial energy rate compares favorably with the present industrial $/kWh energy rate. With the exception of 2001, the present industrial rate appears to be somewhat higher than the cost of service.

6.8 Security Lighting

Norway offers its customers a rate for security lighting for situations where the light is directly wired into the utility distribution system without a meter. Security lighting represents a very small portion of the utility's energy use and billings. Although security lighting represents only a small percentage of Norway's business, it makes sense to charge equitable rates for this service.

Norway's lighting rates are based on electric consumption and maintenance. We can easily estimate the cost for providing security lighting services and compare these costs to the rates presently charged.

Table 20 provides an estimate of Norway's security lighting cost of service. To estimate energy costs, the lamp operating wattage is multiplied by the estimated monthly operating hours to obtain the monthly kWh energy usage for each type of lamp. The residential energy cost of service rate of $0.07284/KWH was identified previously in Table 16 for the study year. This figure is used in Table 20 to determine the monthly lamp operating energy cost. Norway's present monthly rate for security lighting is somewhat lower than the estimated monthly cost of service, particularly for the 250-Watt high-pressure sodium fixtures. Norway may wish to raise the monthly security lighting rate.

Table 19
Industrial Cost of Service Rates

Year	1997	1998	1999	2000	2001	03-04 Budg.	Study Yr.
Monthly Customer Charge (Customer Service)							
Total Customer Service ($)	206,123.00	222,885.40	213,451.40	250,988.70	240,377.10	300,375.80	300,375.80
Ind. Weighted Metering Allocation Factor	1.1%	1.3%	1.2%	1.0%	0.8%	0.7%	0.7%
Ind. Customer Service ($)	2,332.76	2,883.38	2,574.29	2,449.63	1,884.57	2,244.96	2,244.96
Ind. Meters	5	6	6	5	4	4	4
Ind. Monthly Customer Service Charge ($)	38.88	40.05	35.75	40.83	39.26	46.77	46.77
Present Ind. Customer Service Charge ($)	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Street Lighting							
Total Street Lighting ($)	11,664.00	12,999.28	8,455.78	12,533.39	13,351.97	12,845.86	12,845.86
Total Utility Meters	1,853	1,923	2,098	2,176	2,176	2,283	2,283
Monthly Street Lighting Charge	0.52	0.56	0.34	0.48	0.51	0.47	0.47
Present Street Lighting Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand							
Total Power ($)	360,842.80	507,842.35	552,289.90	594,315.55	580,381.65	838,866.60	665,136.28
Ind. Total Demand kW Allocation Factor	12.4%	16.0%	12.0%	10.0%	8.0%	8.2%	8.2%
Ind. Power ($)	44,744.51	81,254.78	66,274.79	59,431.56	46,430.53	68,787.06	54,541.18
Ind. Demand (kW)	657	888	684	590	484	500	500
Ind. Demand Rate ($/kW-Month)	5.67	7.63	8.07	8.39	7.99	11.46	9.09
Ind. Total kWh	2,857,000	3,953,000	3,149,000	2,433,000	1,804,000	1,894,200	1,894,200
Ind. Demand Rate ($/kWh)	0.01566	0.02056	0.02105	0.02443	0.02574	0.03631	0.02879
Energy							
Total Energy ($)	299,625.20	507,251.45	577,922.40	602,398.10	593,035.30	879,465.50	611,370.03
Ind. Energy Allocation Factor	11.2%	15.2%	11.9%	9.0%	6.6%	6.6%	6.6%
Ind. Energy ($)	33,671.45	77,021.01	68,488.48	54,377.49	39,362.58	58,374.33	40,579.55
Ind. kWh	2,857,000	3,953,000	3,149,000	2,433,000	1,804,000	1,894,200	1,894,200
Ind. Energy Rate ($/kWh)	0.01179	0.01948	0.02175	0.02235	0.02182	0.03082	0.02142
Distribution							
Total Distribution System ($)	309,779.00	370,025.40	331,443.40	413,351.70	401,059.10	479,875.80	368,875.80
Ind. Energy Allocation Factor	11.2%	15.2%	11.9%	9.0%	6.6%	6.6%	6.6%
Ind. Distribution System ($)	34,812.52	56,184.62	39,278.72	37,312.58	26,620.21	31,851.65	24,484.05
Ind. kWh	2,857,000	3,953,000	3,149,000	2,433,000	1,804,000	1,894,200	1,894,200
Ind. Distribution Rate ($/kWh)	0.01218	0.01421	0.01247	0.01534	0.01476	0.01682	0.01293
Revenue							
Total Revenue ($)	10,636.00	117,718.12	351,531.12	237,342.56	869,268.88	-99,115.56	478,342.65
Ind. Energy Allocation Factor	11.2%	15.2%	11.9%	9.0%	6.6%	6.6%	6.6%
Ind. Revenue ($)	1,195.26	17,874.31	41,659.28	21,424.53	57,697.53	-6,578.77	31,749.89
Ind. kWh	2,857,000	3,953,000	3,149,000	2,433,000	1,804,000	1,894,200	1,894,200
Ind. Revenue Rate ($/kWh)	0.00042	0.00452	0.01323	0.00881	0.03198	-0.00347	0.01676
Total Ind. Blended Energy Rate ($/kWh)	0.02439	0.03822	0.04745	0.04649	0.06856	0.04416	0.05111
Present Ind. Energy Rate ($/kWh)	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000	0.05000
Present Ind. Demand Rate ($/kW)	6.00	6.00	6.00	6.00	6.00	6.00	6.00

Table 20
Security Lighting Cost of Service

Lamp Type and Wattage	100 Watt High Pressure Sodium	250 Watt High Pressure Sodium	175 Watt Metal Halide
Lamp Operating Wattage	130	295	210
Monthly Operating Hours	310	310	310
Monthly Energy Use (kWh)	40.30	91.45	65.10
Average Utility Energy Cost of Service ($/kWh)	0.07284	0.07284	0.07284
Monthly Lamp Energy Cost ($)	2.94	6.66	4.74
Annual Lamp Maint. Cost ($)	42.00	42.00	46.00
Monthly Lamp Maint. Cost ($)	3.50	3.50	3.83
Totally Monthly Cost ($)	6.44	10.16	8.57
Present Monthly Rate ($)	6.90	6.90	6.90

7.0 Rate Design Theory

The purpose of this section is to provide a general overview of rate design theory and to introduce several trends in electric rate-making. This section should encourage discussion among utility and city personnel to identify the philosophies that might best be incorporated into Norway's rates.

7.1 Electric Rate Design is not Uniform

Electric rate design is not very uniform as can be attested by the wide variations in rate structures of large utilities that have complete departments of rate specialists. Rate design within one utility may be inconsistent between two customer classes. Two utilities may be regulated by the same public service commission and have completely different rate structures.

The foregoing is understandable due to the wide variation in electric consumption patterns among different users and the debt obligations, seasonal variations, energy sources and operating differences among utilities. The philosophical attitudes of utilities and regulatory bodies also play a part. Each utility, including the City of Norway, is thus unique.

7.2 Objectives of Setting Electric Rates

Ideally, electric rates should accomplish the following:

1. Cover utility costs
2. Be competitive with other sources of energy
3. Be competitive with other electric utilities serving the region
4. Be equitable to all customers

In covering utility costs, rates should produce revenue for the following purposes:

1. General operating expenses
   a. Production and purchased energy
   b. Distribution and transmission expenses
   c. Metering, accounting, collection and administration

2. Recover investment
   a. Depreciation
   b. Debt service or interest on depreciated assets

3. City property taxes or transfers to general fund

7.3 Encouraging Energy Conservation

In past years, increased electric energy consumption was encouraged primarily by large investor-owned utilities. Energy consumption is still encouraged today through declining cost block rates. The City of Norway offers a declining block rate for its small industrial customers. This, to a limited extent, encourages increased consumption by offering a lower rate for customers with higher energy consumption patterns. It also rewards these customers for their assumed higher load factor.

Encouraging energy conservation is more prevalent today than encouraging energy consumption. Electric energy conservation is encouraged in an effort to reduce utility investment in generating plants and distribution systems, conserve natural resources and minimize pollution. One means of encouraging energy conservation is through an inverted block rate where the more energy consumed, the higher the rate. Inverted rates have not been readily accepted by the electric industry.

7.4 Time-Of-Day Rates

Although inverted step rates are not likely to be implemented any time soon, several other rates that encourage prudent energy use have seen wide acceptance. Time-of-day rates are established by some utilities to discourage electric energy use when the utility’s cost of purchasing electricity is high. During periods typically associated with low demand, such as at night and on weekends, the rate is low. During periods of high system demand, the rate is high to discourage consumption.

7.5 Off-Peak Rates

Some utilities offer special low off-peak rates for customers that have the flexibility to limit the operation of a specific process during periods of peak system demand. The off-peak rates often apply to electric water heaters, electric furnaces and air conditioning units that are controlled by the utility load management system. The lower rates offset the inconvenience of not having power available at all times for these uses. Golf course irrigation pumps offer another example. If the course has sufficient pumping capacity, it may be able to run the pumps only at night and still provide sufficient moisture for the greens, fairways and tees.

7.6 Peak Curtailment Rate

Another concept to encourage energy conservation is a peak curtailment rate. During periods of high system demand, such as hot summer days when the air conditioning load is high, the customer agrees to limit demand to a specific pre-determined level. The customer can reduce his or her demand by shutting down specific energy-consuming processes or by starting an electric generator to take up some of the load that would normally be carried by the utility.

The time-of-day, off-peak and peak curtailment rates do not necessarily reduce electric consumption but they do encourage wiser use of existing resources. By lowering the peak demand experienced by the utility, these rates help reduce the need for investment in new generating plants and distribution system components. These rates require relatively sophisticated metering. The required metering technology is becoming more prevalent and less costly as more and more utilities promote these and other rate concepts.

7.7 Rate Unbundling

7.7.1 Customer Choice

Customer choice is the key concept in the regulatory changes occurring within the electric industry. Although recent events on both the east and west coasts have slowed the pace of regulatory change in the Midwest, metering technology has advanced to the point where energy consumers need not obtain electric energy from their local utility. The local utility will still control the distribution system that conducts the electricity to the consumer but the delivered electricity need not be provided by the local utility. Electric customers may wish to have a choice in their suppliers and the way they purchase energy. To provide customers with the choices they want, utilities will most likely need to unbundle their electric rates at some future date.

Today's electric rates include many components but these components are typically bundled together by a utility into one rate for residential customers, one rate for commercial customers and one rate for industrial customers. Larger utilities may have several variations in their residential, commercial and industrial rates but the concept remains valid. The various cost components that go into each rate can be separated so that customers have a greater choice in the services they wish to purchase and from whom they purchase.

7.7.2 Cost Accounting for Rate Unbundling

Rate unbundling will require increased attention to record keeping and utility analysis. A careful examination of property and capital equipment records and cost accounting methods may be in order. Careful attention must be placed on property taxes or the transfer to city general fund in order to insure that this community revenue stream remains viable when customers have a choice as to their energy supplier. Additional attention should be placed on documenting the utility's services to other city functions. To fully unbundle their rates, a municipal utility must have a firm understanding of the following costs:

1. Wholesale Power
    a. Demand (kW)
    b. Energy (kWh)
    c. Facilities (substations, transmission, etc.)

2. Generation
    a. Operation and maintenance
    b. Debt service
    c. Depreciation
    d. Return on investment
    e. General and administrative
    f. Fuel

3. Transmission
    a. Operation and maintenance
    b. Debt service
    c. Depreciation
    d. Return on investment
    e. General and administrative

4. Distribution
    a. Operation and maintenance
    b. Debt service
    c. Depreciation
    d. Return on investment
    e. General and administrative

5. Customer Service
   a. Operation and maintenance
   b. Metering, meter reading, billing
   c. General and administrative
   d. Technical advice

6. Special Charges
   a. Hook-up, disconnect
   b. Temporary power
   c. Emergency power
   d. New service drop

7. Transfer to City General Fund

8. Services to the city
   a. Street lighting
   b. Security lighting
   c. Electric service to city buildings
   d. Electric service for municipal water and wastewater systems
   e. Labor and equipment for non-utility city functions

7.7.3 Unbundled Rate Packages

Once the present rate structure is broken down into specific components, the components can be packaged together into discrete packages. Norway does this today, to a certain extent, by offering the residential, commercial and industrial rate packages. Additional rate packages might include time-of-day and peak controlled metering. Future offerings might include emergency power, electric equipment maintenance, transformer service, surge protection, security systems or any other services that the utility may wish to offer.

The rate packages must be useful, viable and make economic sense to customer groups. The rates must be justifiable in the eyes of both customers and regulatory bodies. These rate structures should be reviewed annually to make sure they remain viable as industry regulations evolve and customer preferences change. Utilities must remain in close contact with their customers to understand their wants and needs. The rate packages should provide a collection of services useful to various customer groups and offer those customer groups a clear choice in the services they wish to purchase from the utility.

7.7.4 Procedures for Unbundling

The American Public Power Association (APPA) offers guidelines for identifying the unbundled cost of service rates for electric distribution services and guidelines for establishing the marginal cost for electric generation in a competitive environment. In this rate study, we have applied the APPA guidelines for unbundled cost of service to the City of Norway where feasible. Tables 16 through 19 provide a breakdown of Norway's cost of service rates. Although APPA provides guidelines for identifying the unbundled cost of service, as yet there are no established procedures in place for designing a set of unbundled electric rates for a utility. Perhaps the best way to move toward an unbundled rate structure is incrementally, one step at a time. Although it may be premature for Norway to fully unbundle their rates now, it may make sense to establish a distribution wheeling rate to anticipate customers that may wish to purchase some of their energy services from other providers. Starting with the distribution wheeling rate, Norway can begin to set up a billing structure that will accommodate unbundling. By separating functions and costs, Norway can avoid loosing revenue if customers choose to purchase specific energy services elsewhere.

7.8 Distribution Wheeling Rate

No matter what direction that electric regulatory changes take, electric distribution will remain the key service offered by Norway. It is highly unlikely that any other organization will try to overbuild the utility's existing electrical distribution system. A well-maintained, reliable distribution system presents a nearly insurmountable economic barrier to other organizations wishing to enter Norway's present service area. It is critical that the unbundled rate structure provides revenue sufficient to maintain Norway's distribution system even if some customers choose to purchase energy or related services from other organizations. Customers that buy their energy from outside the Norway system must still use Norway's distribution system to take delivery of the energy they have purchased.

7.8.1 Maintaining Revenue Through the Distribution Wheeling Rate

A distribution wheeling rate can be established to provide sufficient revenue to maintain Norway's distribution system regardless from whom the customers purchase their energy. Each customer would be assessed the distribution wheeling rate on a per kWh basis for electricity from the utility or wheeled across Norway's distribution system from an outside provider. Until complete rate unbundling takes place, Norway can make the distribution wheeling rate an integral part of the residential, commercial and industrial rates.

7.8.2 Cost of Service Distribution Wheeling Rate

The distribution wheeling rate can be based on Norway's cost of service for providing electric distribution to its customers. Recall that Table 3 presented Norway's annual utility operating expenses for the past five years. These costs can be separated into functions associated with customer service, street lighting, power, energy, distribution and revenue as shown in Table 13. All of the costs listed under distribution should be recovered by the distribution wheeling rate.

Tables 16 through 19 present a calculation of Norway's unbundled cost of service rates in $/kWh for the past five years. Each table includes an unbundled cost of service rate for customer service, street lighting, power, energy, distribution and revenue cost components. The distribution cost of service rate would provide a good basis for a distribution wheeling rate. During 2002, for example, the cost of service rate for distribution was $0.01476/kWh. Utility staff may also want to include some of the items in the revenue section of Table 13 when developing the appropriate distribution wheeling rate. The rate should include items such as the transfer to the city general fund so that this funding source for the city will remain viable even from customers who choose to purchase their energy from another supplier.

Note that the cost of service distribution wheeling rate changes from year to year. The variation is primarily due to changes in the amount of maintenance and upgrade expenses associated with the distribution system each year, changes in the contribution to the city general fund and variation in the annual kWh sold. A moving average using three to five years of distribution cost of service rates may be most appropriate for Norway to smooth out the effects of abnormal costs in any one area.

7.9 Cost of Energy Adjustment Clause

7.9.1 Energy Cost Variation

Wholesale power costs typically vary according to the wholesale supplier's fuel costs. We Energies, Norway's wholesale power provider, passes these costs on to Norway in the form of a fuel clause adjustment each month. Wholesale power costs are particularly high during periods of system peak demand.

7.9.2 Cost of Energy Adjustment Clause

The City of Norway may wish to establish a cost of energy adjustment clause to pass any additional costs on to its customers. The cost of energy adjustment clause would establish a base rate for purchased energy. If the purchased energy cost rises above the base rate, the utility could pass these costs on to its customers without a formal rate increase hearing. The base rate should be adjusted from time to time to reflect Norway's present costs. These costs were presented in the energy purchases (energy and demand) line items near the center of Table 3. During 2001, the purchased energy expense was $111,613 and the purchased demand expense was $207,280. The sum of these expenses, $318,893 can be divided by the 2001 annual electric sales of 27,179,000 kWh from Table 7 to obtain an average cost of $0.01173/kWh distributed. Norway can use a similar calculation to establish an energy cost adjustment base should the need ever arise.

Energy cost adjustments typically are accomplished through a rolling three-month average to minimize sharp variations that may occur during a single month. If Norway establishes an energy cost adjustment clause, SEH recommends a practice of combining the current month with the two previous months when making the comparison with the base rate. Many utilities have an energy cost adjustment clause in their rate tariff that establishes an addition for months when the purchased energy and fuel costs are high as well as a subtraction for months when these costs are low. SEH generally recommends that the subtraction be eliminated from these rate tariffs. In the unlikely event that energy costs fall, any unanticipated revenue can be allocated to utility reserves where it will eventually be spent on capital improvements that contribute to system reliability and benefit all customers. The cost of energy adjustment base should be reviewed periodically, along with the utility rates in general, and adjusted to reflect Norway's ongoing financial situation.

7.9.3 Maintenance/Capital Cost Adjustment Clause

Norway may also wish to establish a maintenance cost adjustment clause as part of the electric rate structure. Unanticipated or extraordinary maintenance expenditures for the generation plant or distribution system could then be recovered through the maintenance cost adjustment clause, with anything over perhaps $75,000 considered an unusual maintenance expense. If, for example, the utility experienced an unexpected cost of $100,000 for distribution repairs, the utility could establish an adjustment of $0.00368/kWh. This figure was derived by dividing the $100,000 unanticipated cost by the 2001 annual electric sales of 27,179,000 kWh. The rate adjustment would remain in effect for approximately one year or whenever the original $100,000 was recovered. A provision can also be included in the utility's rate statement that will allow, at the utility or city council's discretion, extraordinary costs for capital expenditures to be recovered through the maintenance cost adjustment clause. This provides the capability of recovering, through temporary rate adjustments, any planned or unplanned extraordinary costs encountered by the utility.

7.10 Monthly Customer Charge

The City of Norway presently assesses a monthly customer charge. A movement in the industry exists toward using the monthly customer charge to recover more of the general & administrative and even the distribution system costs. Expanding the monthly customer charge helps reduce the dependency on stable kWh energy sales. If the industry movement toward deregulation accelerates and customers begin to have increasing choice in their energy suppliers, it may become ever more difficult to predict future utility costs and energy sales. Predicting costs and energy sales is critical to establishing rates on an average $/kWh cost of service basis. Recovering all costs through an average $/kWh basis may expose Norway to increasing risk going forward.

Another argument toward recovering more costs through the monthly customer charge is the fact that nearly all of the general & administrative costs and many costs associated with distribution are fixed and do not vary with energy kWh. These costs largely represent overhead expenses that are incurred regardless of the amount of energy sold in any one particular month. The cost of maintaining meters, service drops, line transformers, primary distribution lines and even substation transformers is largely independent of monthly kWh distributed.

If electric industry movement accelerates toward greater customer choice through deregulation, Norway's focus will most likely be on electric distribution. Each community member will use Norway's distribution system to obtain electricity delivery but may not necessarily purchase the electricity from Norway. Under these circumstances, it may be prudent to expand the fixed monthly customer charge to help cover more of the utility's costs.

7.10.1 Recovering Fixed Costs Through the Monthly Customer Charge

The monthly customer charge should cover, as a minimum, the utility's costs for meter reading labor, accounting and collection labor, billing postage and expenses, and providing technical assistance. Technical assistance involves answering questions, responding to customer concerns, and any other customer contacts. These are all fixed costs for the utility and do not vary with the amount of kWh energy sold.

The City of Norway does not presently break out its costs for meter reading labor, accounting and collection labor, billing postage and expenses, and providing technical assistance. Much of this cost is covered under general expenses in the annual utility financial report. As the utility regulatory climate continues to change, it may become worthwhile for Norway to better document these expenses in an effort to recover them through a higher monthly customer charge. The monthly charges of neighboring utilities should also be reviewed as part of the decision-making process. The monthly customer charge will help recover Norway's fixed costs while retaining the utility's competitiveness with neighboring utilities.

8.0 Proposed Rates

The City of Norway has not enacted an electric rate increase since 1994. During the study period between 1997 and 2001, Norway's utility costs, including contributions to other city funds, have increased significantly. If this trend in utility costs continues, Norway must eventually raise its customer rates to generate enough revenues to cover the expense obligations. In addition, an imbalance appears to exist between the rates of residential, commercial and industrial customers. The rates paid by commercial and industrial customers appear to be subsidizing, to a limited extent, the rates for residential customers. Several adjustments should be made to better balance the burden of electric costs among Norway's electric customers.

Table 21 presents Norway's existing and proposed rates, along with the rates of neighboring Escanaba Municipal and Gladstone Municipal. The neighboring rates are presented for comparison with the existing and proposed Norway rates. Our proposed rates are based on a number of factors as discussed previously in the section on rate design theory. Norway's existing rates represent the most important of these factors, followed perhaps by cost of service, the rates of neighboring utilities, and allocating utility costs fairly among the customer types. The following paragraphs provide a description of some of the key rate changes we are proposing and the reasoning behind these suggested changes.

8.1 Rate Increase

The proposed rates represent a significant increase to utility customers as will become evident in subsequent pages of the rate study report. The increase is needed if Norway plans to continue making timely improvements in the generating plant and distribution system. The improvements will be needed to maintain system safety and reliability. The proposed rate increase is quite large because the community has not assessed a rate increase for nearly ten years. We recommend that the increase by broken down into two or three smaller increases over several years to ease the burden on those customers who may find it more difficult to budget for one large increase.

Table 21
Proposed Rates

		Present Norway (City)	Proposed Norway (City)	Escanaba	Gladstone
Residential					
Monthly Customer Charge ($)		3.00	5.00	2.39	3.00
Energy Charge ($/kWh)	1st 400 kWh	0.05500	0.07000	0.07175	0.07000
Energy Charge ($/kWh)	Over 400 kWh	0.05500	0.07000	0.06343	0.07000
Commercial (Single Phase)					
Monthly Customer Charge ($)		10.00	12.00	2.39	4.00
Energy Charge ($/kWh)	1st 500 kWh	0.06500	0.07700	0.08942	0.07000
Energy Charge ($/kWh)	500 to 2,000 kWh	0.06500	0.07700	0.06759	0.07000
Energy Charge ($/kWh)	Over 2,000 kWh	0.06500	0.07700	0.06343	0.07000
Small Industrial					
Monthly Customer Charge ($)		20.00	20.00	0.00	10.00
Energy Charge ($/kWh)	1st 1,000 kWh	0.09500	0.09500	0.05200	0.05500
Energy Charge ($/kWh)	1,000 to 20,000 kWh	0.06500	0.06500	0.05200	0.05500

Table 21 (Continued)
Proposed Rates

		Present Norway (City)	Proposed Norway (City)	Escanaba	Gladstone
Industrial					
Monthly Customer Charge ($)		20.00	22.00	0.00	40.00
Energy Charge ($/kWh)	1st 50,000 kWh	0.05000	0.05500	0.05200	0.04300
Energy Charge ($/kWh)	50,000 to 200,000 kWh	0.05000	0.05500	0.04900	0.04300
Energy Charge ($/kWh)	Over 200,000 kWh	0.05000	0.05500	0.04600	0.04300
Monthly Demand ($/KW)	All kW	6.00	7.00	3.27	4.00
Security Lighting					
Monthly Customer Charge ($)		6.90	10.00	9.63	10.04

8.2 Monthly Customer Charge

One of the changes we recommend is a gradual increase in the monthly customer charge. In the previous section on monthly customer charge, we discussed at length the utility movement toward using the monthly customer charge to recover more of the general & administrative and even the distribution system costs. Expanding the monthly customer charge helps reduce the dependency on stable wholesale energy costs and predictable annual kWh energy retail sales. If the industry movement toward deregulation accelerates and customers begin to have increasing choice in their energy suppliers, these customers must still take delivery through Norway's distribution system and customer meters. The customers would pay the monthly customer charge to Norway even if they purchase their kWh energy from a source other than Norway.

We recommend that Norway begin making strategic increases in the monthly customer charge this fall as indicated in Table 21. These changes should be made gradually and made with care because they affect small customers much more significantly than large users. The customer charge represents a much greater portion of the monthly bill for a small customer than it does for a large energy user. A rate increase may result in more financial hardship for small customers than it does for large users.

8.3 Small Industrial Customer Class

There are presently only four customers in the small industrial rate classification. From our perspective, it would seem prudent to eliminate the small industrial class and move these four customers into the industrial rate class. The utility would need to install demand meters for these customers if they do not presently have them. In Table 21, we have not shown any rate changes for the small industrial customers since their rates are already quite high and it appears that they would be best served under the industrial rate classification.

8.4 Distribution Wheeling Rate

A distribution wheeling rate of at least $0.01476/kWh can be incorporated into each of the proposed residential, commercial and city rates. Any power supplier wishing to use Norway's distribution system to wheel power to a customer would be charged the distribution wheeling rate. The distribution wheeling rate will help finance the utility's capital expenses and operating costs associated with the distribution system even when the customer's electricity is supplied by an organization other than Norway. This distribution rate does not represent an increase in Norway's rates for customers purchasing energy from the utility. It is included in the $/kWh energy rates for each customer class. At the present time, this distribution wheeling rate has no real impact. The establishment of this rate can serve as a contingency in the event that retail electric customers in Michigan are given greater opportunities to choose their energy supplier.

8.5 Energy Cost Adjustment Clause

An energy cost adjustment clause may not be necessary at this time because Norway generates a significant amount of its own power. An alternative to the energy cost adjustment is to make modest increases to the $/kWh energy rates each year. This increase serves in part to anticipate the energy cost adjustments made by We Energies. In future years, the wholesale energy market is expected to become increasingly volatile and Norway may find it more difficult to anticipate the cost of wholesale energy. Any required rate adjustments would be made automatically on a monthly basis without a formal public rate hearing at a city council meeting.

City council or Utility Board/Commission approval would be initially required to establish the energy cost adjustment clause and to establish a baseline wholesale energy cost but would not normally be needed each year to confirm an annual Norway rate adjustment to accommodate We Energies' cost adjustments. Formal rate increases would still be required, however, to address any other major changes in Norway's wholesale power costs. Finally, Norway may wish to restrict the energy cost adjustment to accommodate only the increases in energy costs. In the unlikely event of a decrease in energy costs, any extra customer revenues would be directed to utility reserves where they would eventually benefit the entire community instead of being returned to the customers in the form of a credit to their accounts.

8.6 Maintenance Cost Adjustment Clause

The City of Norway may wish to establish a maintenance cost adjustment clause to allow the utility to recover unanticipated or extraordinary maintenance expenditures. An example of extraordinary maintenance might be repairs resulting from storm damage. A provision could also be included in Norway's rate statement that will allow, at the utility's discretion, extraordinary costs for capital expenditures to be recovered through the maintenance cost adjustment clause.

8.7 Security Lighting

The cost of service for security lighting was presented earlier in Table 20. Norway's monthly rates for all security lighting options are somewhat lower than the estimated monthly cost of service. SEH recommends that the present $6.90 monthly security lighting rates be increased to $10.00 per month. An immediate change to $10.00 represents an increase of 45%. It might be better instead to gradually increase the security lighting rate by about $1.00 per month over a period of several years. For next year, the rate would be raised to $8.00, and then again to $9.00 the following year, etc.

9.0 Revenues Under Existing and Proposed Rates

The proposed rates will have an impact on Norway's annual customer revenues. It is important for the utility to understand the extent of this impact. The proposed rates must provide sufficient customer revenues to meet the financial obligations of the utility. The revenue impact for each customer class is discussed below.

9.1 Residential Customer Revenues Under Existing and Proposed Rates

The existing and proposed rates can be applied to the historic community energy consumption patterns to identify the impact on utility revenues. Table 22 presents the estimated annual revenues from residential customers during the past five years under the present and proposed rates. The table also includes the 2003-2004 budget year and the study year. In the table, we have applied the present 2002 rates and our proposed rates to each year of historic and projected residential energy consumption data.

The proposed rates provide an increase of nearly 30% in annual residential customer revenues due to the increase in the monthly customer charge and in the $/kWh energy rate. As mentioned previously, this is a significant proposed rate increase and it may be wise to break down the increase into two or three smaller increments over several years. Comparing Table 22 to Tables 23 through 25, note that the residential rate increase is significantly higher than the increases proposed for commercial and industrial customers. Earlier in the report, we showed that the residential customers appeared to be subsidized, to a limited extent by the commercial and industrial customers. A higher rate increase for residential customers will more fairly distribute the costs of operating the utility among the three major customer classes.

9.2 Commercial Customer Revenues Under Existing and Proposed Rates

Table 23 presents the estimated annual revenues from commercial customers during the past five years under the present and proposed rates and is similar to Table 22 for residential customers. In the table, we have applied the present 2002 rates and our proposed rates to each year of historic and projected residential energy consumption data. The proposed rates provide an increase of about 18.5% in annual commercial customer revenues due to the increase in the monthly customer charge and in the $/kWh energy rate. Again, this is a significant proposed rate increase and it may be wise to break down the increase into two or three smaller increments over several years. The commercial rate increase is significantly lower than the increase proposed for residential customers but higher than the increase proposed for industrial customers. This will help balance the costs of operating the utility among the three major customer classes.

9.3 Small Industrial Customer Revenues Under Existing and Proposed Rates

Table 24 shows no changes to the small industrial customer rates or revenues. As we noted previously, there are only four customers in the small industrial classification and it appears that these businesses could be served under the industrial rates.

9.4 Industrial Customer Revenues Under Existing and Proposed Rates

Table 25 presents the estimated annual revenues from industrial customers during the past five years under the present and proposed rates and is similar to Table 23 and 24 for residential and small industrial customers. The proposed rates provide an increase of about 13% in annual industrial customer revenues due to the increases in the monthly customer charge, $/kWh energy rate and $/kW demand rate. The industrial rate increase is significantly lower than the increases proposed for residential and commercial customers to better balance the costs of operating the utility among the three major customer classes.

9.5 Total System Customer Revenues Under Existing and Proposed Rates

Table 26 presents a summary of the estimated annual revenues for all customer classes during the past five years under the present and proposed rates. In the table, we have totaled up the customer class revenues for each year. The table shows a system wide customer revenue increase of approximately 23%. The projected total system revenues and kWh energy sales under the proposed electric rates can be plotted in the form of two pie charts as shown in Charts 5 and 6. Charts 5 and 6 can be compared to Charts 3 and 4 presented earlier.

Charts 5 and 6 under the proposed rates demonstrate a much better balance between kWh energy consumption and customer revenues than was shown in Charts 3 and 4 under the present electric rates.

Chart 5 – Residential Rates

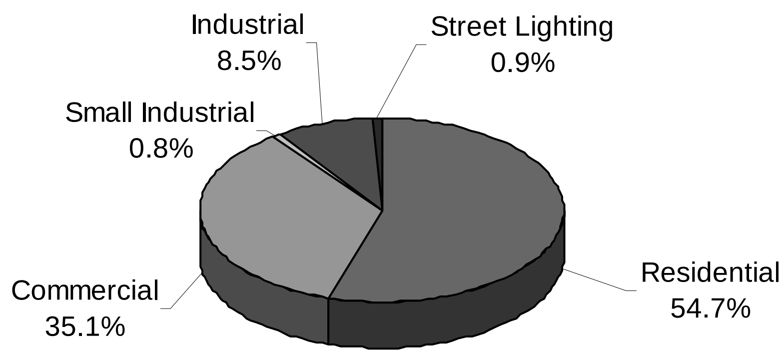


Chart 6 – Commercial Rates

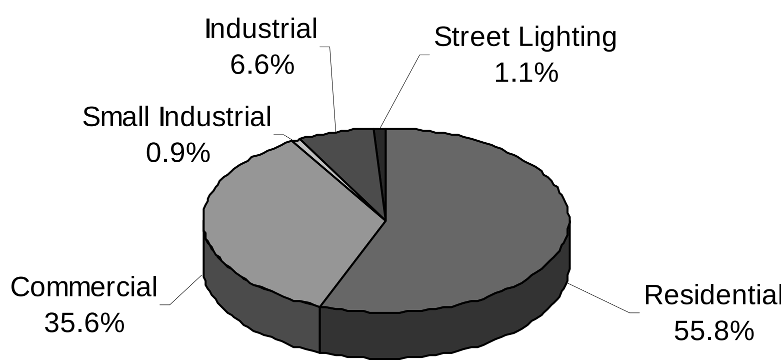


Table 22
Residential Customer Revenues Under Existing and Proposed Rates

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed
Number of Meters	1669	1669	1720	1720	1897	1897	1976	1976	1979	1979	2077	2077	2077	2077
Monthly Customer Charge ($)	3.00	5.00	3.00	5.00	3.00	5.00	3.00	5.00	3.00	5.00	3.00	5.00	3.00	5.00
Customer Charge Revenue ($)	60,084.00	100,140.00	61,920.00	103,200.00	68,292.00	113,820.00	71,136.00	118,560.00	71,244.00	118,740.00	74,772.00	124,620.00	74,772.00	124,620.00
Energy (kWh)	10,770,000	10,770,000	7,970,667	7,970,667	8,842,667	8,842,667	9,555,333	9,555,333	10,108,000	10,108,000	10,613,400	10,613,400	10,613,400	10,613,400
Township Energy (kWh)	5,385,000	5,385,000	3,985,333	3,985,333	4,421,333	4,421,333	4,777,667	4,777,667	5,054,000	5,054,000	5,306,700	5,306,700	5,306,700	5,306,700
City Energy Charge ($/kWh)	0.05500	0.07000	0.05500	0.07000	0.05500	0.07000	0.05500	0.07000	0.05500	0.07000	0.05500	0.07000	0.05500	0.07000
Township Energy Charge ($/kWh)	0.06000	0.07500	0.06000	0.07500	0.06000	0.07500	0.06000	0.07500	0.06000	0.07500	0.06000	0.07500	0.06000	0.07500
City Energy Revenue ($)	592,350.00	753,900.00	438,386.67	557,946.67	486,346.67	618,986.67	525,543.33	668,873.33	555,940.00	707,560.00	583,737.00	742,938.00	583,737.00	742,938.00
Township Energy Revenue ($)	323,100.00	403,875.00	239,120.00	298,900.00	265,280.00	331,600.00	286,660.00	358,325.00	303,240.00	379,050.00	318,402.00	398,002.50	318,402.00	398,002.50
Total Revenue ($)	975,534.00	1,257,915.00	739,426.67	960,046.67	819,918.67	1,064,406.67	883,339.33	1,145,758.33	930,424.00	1,205,350.00	976,911.00	1,265,560.50	976,911.00	1,265,560.50
Percent Change (%)	28.9%		29.8%		29.8%		29.7%		29.5%		29.5%		29.5%	

Table 23
Commercial Customer Revenues Under Existing and Proposed Rates

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed
Number of Meters	171	171	189	189	186	186	186	186	183	183	192	192	192	192
Monthly Customer Charge ($)	10.00	12.00	10.00	12.00	10.00	12.00	10.00	12.00	10.00	12.00	10.00	12.00	10.00	12.00
Customer Charge Revenue ($)	20,520.00	24,624.00	22,680.00	27,216.00	22,320.00	26,784.00	22,320.00	26,784.00	21,960.00	26,352.00	23,040.00	27,648.00	23,040.00	27,648.00
Energy (kWh)	5,901,080	5,901,080	9,616,611	9,616,611	9,645,948	9,645,948	9,669,333	9,669,333	9,686,765	9,686,765	10,171,103	10,171,103	10,171,103	10,171,103
Energy Charge ($/kWh)	0.06500	0.07700	0.06500	0.07700	0.06500	0.07700	0.06500	0.07700	0.06500	0.07700	0.06500	0.07700	0.06500	0.07700
Energy Revenue ($)	383,570.20	454,383.16	625,079.72	740,479.05	626,986.62	742,738.00	628,506.65	744,538.64	629,639.73	745,880.91	661,121.70	783,174.93	661,121.70	783,174.93
Total Revenue ($)	404,090.20	479,007.16	647,759.72	767,695.05	649,306.62	769,522.00	650,826.65	771,322.64	651,599.73	772,232.91	684,161.70	810,822.93	684,161.70	810,822.93
Percent Change (%)	18.5%		18.5%		18.5%		18.5%		18.5%		18.5%		18.5%	

Table 24
Small Industrial Customer Revenues Under Existing and Proposed Rates

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed
Number of Meters	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Monthly Customer Charge ($)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
Customer Charge Revenue ($)	960.00	960.00	960.00	960.00	960.00	960.00	960.00	960.00	960.00	960.00	960.00	960.00	960.00	960.00
Energy (kWh)	138,920	138,920	226,389	226,389	227,079	227,079	227,630	227,630	232,235	232,235	243,846	243,846	243,846	243,846
Energy Charge 1st 1,000 kWh ($/kWh)	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500	0.09500
Energy Charge 1,000 to 20,000 kWh ($/kWh)	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500	0.06500
Energy Revenue 1st 1,000 kWh ($)	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00	4,560.00
Energy Revenue 1,000 to 20,000 kWh ($)	5,909.80	5,909.80	11,595.29	11,595.29	11,640.14	11,640.14	11,675.95	11,675.95	11,975.28	11,975.28	12,729.99	12,729.99	12,729.99	12,729.99
Total Revenue ($)	11,429.80	11,429.80	17,115.29	17,115.29	17,160.14	17,160.14	17,195.95	17,195.95	17,495.28	17,495.28	18,249.99	18,249.99	18,249.99	18,249.99
Percent Change (%)	0.0%		0.0%		0.0%		0.0%		0.0%		0.0%		0.0%	

Note: Assumes that all Sm. Ind. Customers use over 1,000 kWh/Mo.

Table 25
Industrial Customer Revenues Under Existing and Proposed Rates

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed
Number of Meters	5	5	6	6	6	6	5	5	4	4	4	4	4	4
Monthly Customer Charge ($)	20.00	22.00	20.00	22.00	20.00	22.00	20.00	22.00	20.00	22.00	20.00	22.00	20.00	22.00
Customer Charge Revenue ($)	1,200.00	1,320.00	1,440.00	1,584.00	1,440.00	1,584.00	1,200.00	1,320.00	960.00	1,056.00	960.00	1,056.00	960.00	1,056.00
Energy (kWh)	2,857,000	2,857,000	3,953,000	3,953,000	3,149,000	3,149,000	2,433,000	2,433,000	1,804,000	1,804,000	1,894,200	1,894,200	1,894,200	1,894,200
Demand (kW)	9,984	9,984	13,019	13,019	15,766	15,766	13,658	13,658	12,850	12,850	13,000	13,000	13,000	13,000
Energy Charge ($/kWh)	0.05000	0.05500	0.05000	0.05500	0.05000	0.05500	0.05000	0.05500	0.05000	0.05500	0.05000	0.05500	0.05000	0.05500
Demand Charge ($/kW)	6.00	7.00	6.00	7.00	6.00	7.00	6.00	7.00	6.00	7.00	6.00	7.00	6.00	7.00
Energy Revenue ($)	142,850.00	157,135.00	197,650.00	217,415.00	157,450.00	173,195.00	121,650.00	133,815.00	90,200.00	99,220.00	94,710.00	104,181.00	94,710.00	104,181.00
Demand Revenue ($)	59,901.00	69,884.50	78,115.00	91,134.17	94,596.00	110,362.00	81,947.00	95,604.83	77,097.00	89,946.50	78,000.00	91,000.00	78,000.00	91,000.00
Total Revenue ($)	203,951.00	228,339.50	277,205.00	310,133.17	253,486.00	285,141.00	204,797.00	230,739.83	168,257.00	190,222.50	173,670.00	196,237.00	173,670.00	196,237.00
Percent Change (%)	12.0%		11.9%		12.5%		12.7%		13.1%		13.0%		13.0%	

Table 26
Total System Customer Revenue Under Existing and Proposed Rates

Year	1997		1998		1999		2000		2001		03-04 Budg.		Study Yr.	
	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed	Existing	Proposed
Residential Revenue ($)	975,534.00	1,257,915.00	739,426.67	960,046.67	819,918.67	1,064,406.67	883,339.33	1,145,758.33	930,424.00	1,205,350.00	976,911.00	1,265,560.50	976,911.00	1,265,560.50
Commercial Revenue ($)	404,090.20	479,007.16	647,759.72	767,695.05	649,306.62	769,522.00	650,826.65	771,322.64	651,599.73	772,232.91	684,161.70	810,822.93	684,161.70	810,822.93
Small Industrial Revenue ($)	11,429.80	11,429.80	17,115.29	17,115.29	17,160.14	17,160.14	17,195.95	17,195.95	17,495.28	17,495.28	18,249.99	18,249.99	18,249.99	18,249.99
Industrial Revenue ($)	203,951.00	228,339.50	277,205.00	310,133.17	253,486.00	285,141.00	204,797.00	230,739.83	168,257.00	190,222.50	173,670.00	196,237.00	173,670.00	196,237.00
Total Revenue ($)	1,595,005.00	1,976,691.46	1,681,506.67	2,054,990.17	1,739,871.42	2,136,229.80	1,756,158.93	2,165,016.76	1,767,776.00	2,185,300.68	1,852,992.69	2,290,870.42	1,852,992.69	2,290,870.42
Percent Change (%)	23.9%		22.2%		22.8%		23.3%		23.6%		23.6%		23.6%	

10.0 Customer Impact of Proposed Rates

The proposed rates will have financial impacts on Norway's present customers. The impacts on residential, commercial, small industrial and industrial customers are discussed as follows.

10.1 Residential Customer Cost Comparison Under Existing and Proposed Rates

The proposed rate changes will have a significant financial impact on residential customers. Recall that we are proposing that the $3.00 monthly customer charge be increased to $5.00. The average 2002 residential utility customer of 638 kWh per month will experience an annual cost increase of $139 or about 30% as illustrated in Table 27. Small customers, having an energy use of 350 kWh per month, will experience an increase of $87 or $7.25 per month but this represents a slightly larger percentage of their annual energy cost due to the impact of the monthly customer charge. Large residential customers, having an energy use of around 1,200 kWh, will experience a $240 increase, representing an impact of 29% to their annual electric energy costs. The existing and proposed Norway residential rates can be plotted with those of neighboring Escanaba and Gladstone as presented in Chart 7. The proposed rates put Norway slightly higher than the neighboring utilities.

10.2 Commercial Customer Cost Comparison Under Existing and Proposed Rates

The proposed rate changes will have a modest financial impact on commercial customers. Norway's average 2001 commercial customer of 4,411 kWh per month will experience an annual cost increase of about $635 or 18.5% as illustrated in Table 28. Small customers having an energy use of 1,700 kWh per month will experience an annual increase of $269, representing 18.6% of their electric energy costs. Large commercial customers having an energy use of say, 5,500 kWh, will experience an increase of about $816 or $68 per month. The existing and proposed Norway commercial rates can be plotted with those of neighboring Escanaba and Gladstone as presented in Chart 8. The proposed rates remain competitive with respect to the neighboring utilities.

Table 27
Residential Customer Costs Under Existing and Proposed Rates

	Small Customer		Average Customer		Large Customer	
	Existing	Proposed	Existing	Proposed	Existing	Proposed
Basic Energy (kWh/Month)	350	350	638	638	1200	1200
Customer Service Cost						
Monthly Customer Charge ($)	3.00	5.00	3.00	5.00	3.00	5.00
Annual Total Cost ($)	36.00	60.00	36.00	60.00	36.00	60.00
Energy Cost						
Energy Rate ($/kWh)	0.05500	0.07000	0.05500	0.07000	0.05500	0.07000
Annual Total Cost ($)	231.00	294.00	421.38	536.30	792.00	1,008.00
Total Energy Annual Cost ($)	267.00	354.00	457.38	596.30	828.00	1,068.00
Percent Change (%)	32.6%		30.4%		29.0%	

Table 28
Commercial Customer Costs Under Existing and Proposed Rates

	Small Customer		Average Customer		Large Customer	
	Existing	Proposed	Existing	Proposed	Existing	Proposed
Basic Energy (kWh/Month)	1,700	1,700	4,411	4,411	5,500	5,500
Customer Service Cost						
Monthly Customer Charge ($)	10.00	12.00	10.00	12.00	10.00	12.00
Annual Total Cost ($)	120.00	144.00	120.00	144.00	120.00	144.00
Energy Cost						
Energy Rate ($/kWh)	0.06500	0.07700	0.06500	0.07700	0.06500	0.07700
Annual Total Cost ($)	1,326.00	1,570.80	3,440.65	4,075.85	4,290.00	5,082.00
Total Energy Annual Cost ($)	1,446.00	1,714.80	3,560.65	4,219.85	4,410.00	5,226.00
Percent Change (%)	18.6%		18.5%		18.5%	

Chart 7 – Residential Rates

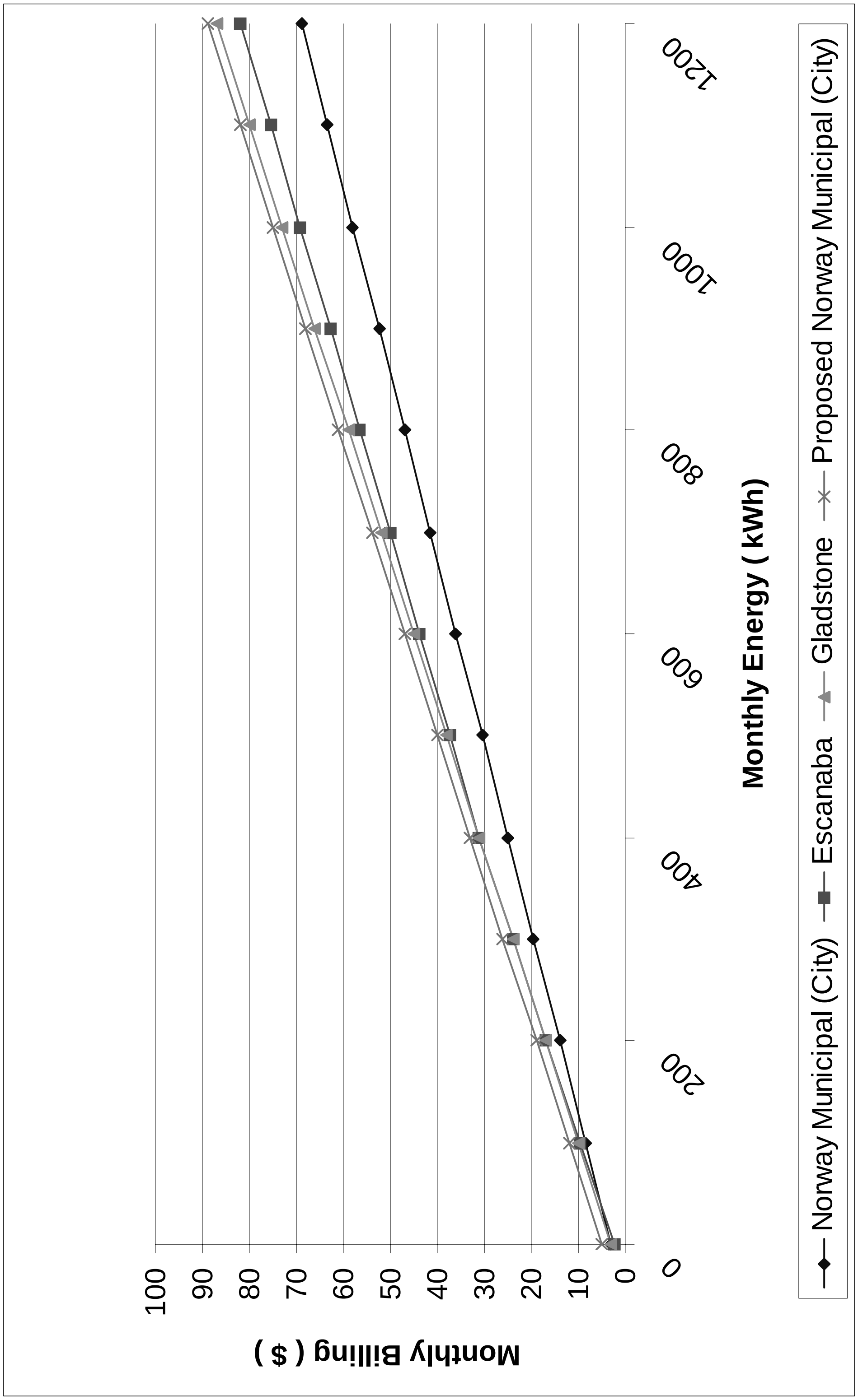
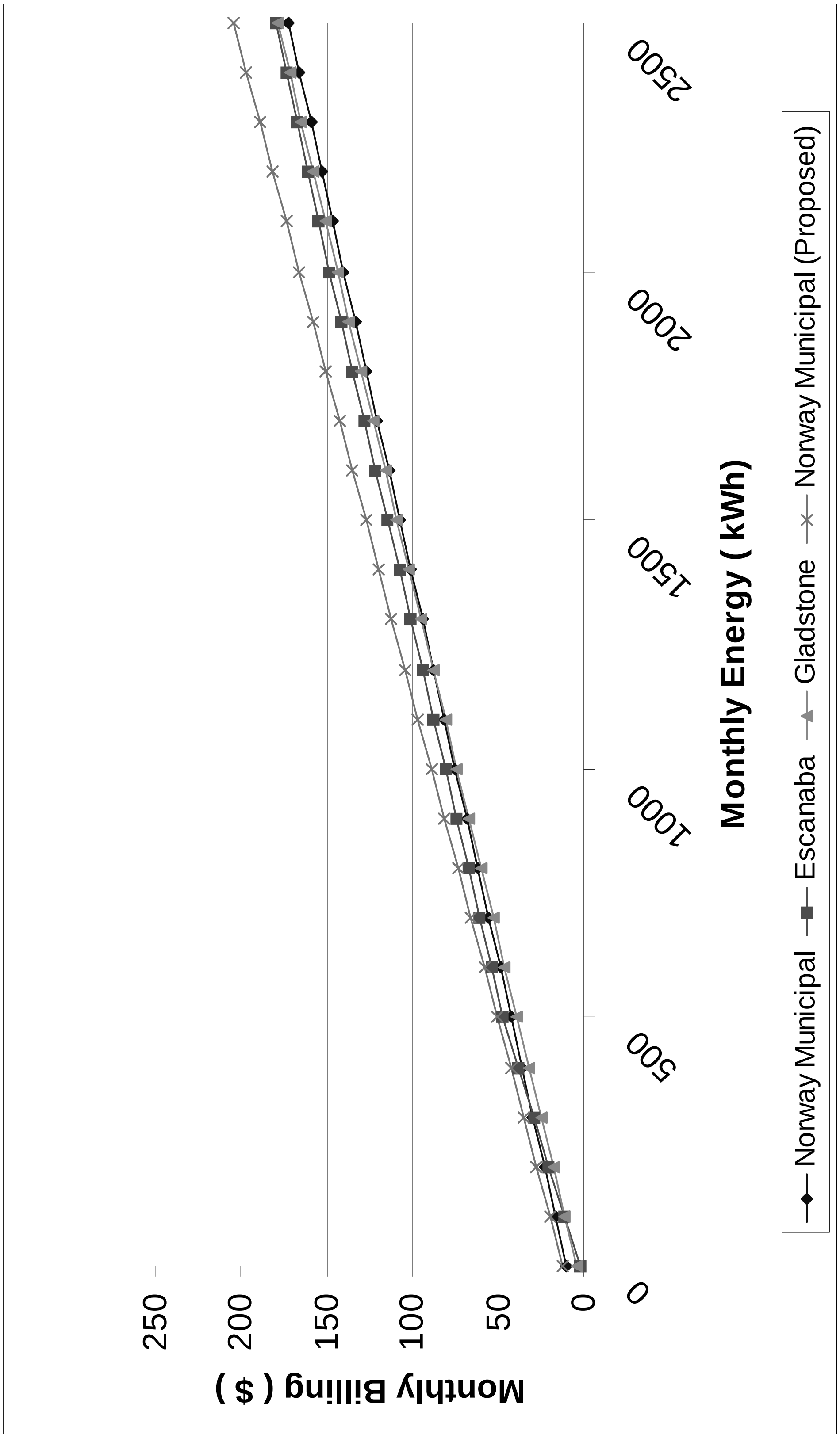


Chart 8 – Commercial Rates



10.3 Individual Customer Cost Comparisons Under Existing and Proposed Rates

Industrial customers pay a monthly $/kW demand charge in addition to the $/kWh energy cost and monthly customer charge. Each industrial customer has a unique relationship between monthly peak demand and annual energy consumption. For this reason, the financial impact of rate changes on industrial customers is best accomplished on an individual basis.

Table 29A presents the annual energy cost for one of Norway's industrial customers under the present rates using energy consumption data for 2002. Table 29B presents the annual cost under the proposed rates. The proposed electric rates result in a 10.8% increase in annual energy costs for this customer based on the relationship between energy and demand for 2002. Tables 30A and 30B present the cost impact of the proposed rate change on another industrial customer. The proposed rates result in an overall increase of 10.4% in electric energy costs.

Tables 31A through 33B present the annual energy costs for selected commercial customers under the present and proposed rates. Along with the industrial customers discussed above, these commercial accounts represent some of Norway's key customers. An analysis of the small industrial customers would also be worthwhile. Under the proposed rates, the small industrial customer class would be eliminated and these customers would join the industrial rate classification. Unfortunately, past kW demand data is not available for the small industrial customers so we cannot accurately predict the financial impact that the proposed rates will have on these customers. A significant annual increase in electric costs for the small industrial customers is not expected since the present small industrial electric rates are quite high already.

Table 29A
Industrial Customer Billing - 2002 Industrial Rates

Month	2002 Energy Use kWh	Demand kW	Service Charge $	Energy Charge $/kWh	Demand Charge $/kW	Energy Cost $	Demand Cost $	Total Cost $
Jan	26,450	104	20.00	0.05000	6.00	1,322.50	621.00	1,963.50
Feb	27,600	92	20.00	0.05000	6.00	1,380.00	552.00	1,952.00
Mar	25,300	115	20.00	0.05000	6.00	1,265.00	690.00	1,975.00
April	31,050	100	20.00	0.05000	6.00	1,552.50	600.00	2,172.50
May	18,400	100	20.00	0.05000	6.00	920.00	600.00	1,540.00
June	24,150	104	20.00	0.05000	6.00	1,207.50	621.00	1,848.50
July	26,450	104	20.00	0.05000	6.00	1,322.50	621.00	1,963.50
Aug	25,300	115	20.00	0.05000	6.00	1,265.00	690.00	1,975.00
Sept	26,450	115	20.00	0.05000	6.00	1,322.50	690.00	2,032.50
Oct	26,450	92	20.00	0.05000	6.00	1,322.50	552.00	1,894.50
Nov	35,650	103	20.00	0.05000	6.00	1,782.50	618.00	2,420.50
Dec	26,850	104	20.00	0.05000	6.00	1,342.50	621.00	1,983.50
Total	**320,100**		**240.00**			**16,005.00**	**7,476.00**	**23,721.00**

Notes: Actual Data from Dec 2001

Table 29B
Industrial Customer Billing - 2003 Industrial Rates

Month	2002 Energy Use kWh	Demand kW	Service Charge $	Energy Charge $/kWh	Demand Charge $/kW	Energy Cost $	Demand Cost $	Total Cost $
Jan	26,450	104	22.00	0.05500	7.00	1,454.75	724.50	2,201.25
Feb	27,600	92	22.00	0.05500	7.00	1,518.00	644.00	2,184.00
Mar	25,300	115	22.00	0.05500	7.00	1,391.50	805.00	2,218.50
April	31,050	100	22.00	0.05500	7.00	1,707.75	700.00	2,429.75
May	18,400	100	22.00	0.05500	7.00	1,012.00	700.00	1,734.00
June	24,150	104	22.00	0.05500	7.00	1,328.25	724.50	2,074.75
July	26,450	104	22.00	0.05500	7.00	1,454.75	724.50	2,201.25
Aug	25,300	115	22.00	0.05500	7.00	1,391.50	805.00	2,218.50
Sept	26,450	115	22.00	0.05500	7.00	1,454.75	805.00	2,281.75
Oct	26,450	92	22.00	0.05500	7.00	1,454.75	644.00	2,120.75
Nov	35,650	103	22.00	0.05500	7.00	1,960.75	721.00	2,703.75
Dec	26,850	104	22.00	0.05500	7.00	1,476.75	724.50	2,223.25
Total	**320,100**		**264.00**			**17,605.50**	**8,722.00**	**26,591.50**
Percent Change								**10.8%**

Notes: Actual Data from Dec 2001

Table 30A
Industrial Customer Billing - 2002 Industrial Rates

Month	2002 Energy Use kWh	Demand kW	Service Charge $	Energy Charge $/kWh	Demand Charge $/kW	Energy Cost $	Demand Cost $	Total Cost $
Jan	287,500	805	20.00	0.05000	6.00	14,375.00	4,830.00	19,225.00
Feb	331,200	817	20.00	0.05000	6.00	16,560.00	4,899.00	21,479.00
Mar	313,950	817	20.00	0.05000	6.00	15,697.50	4,899.00	20,616.50
April	471,500	1,000	20.00	0.05000	6.00	23,575.00	6,000.00	29,595.00
May	270,250	1,000	20.00	0.05000	6.00	13,512.50	6,000.00	19,532.50
June	435,850	1,139	20.00	0.05000	6.00	21,792.50	6,831.00	28,643.50
July	542,800	1,127	20.00	0.05000	6.00	27,140.00	6,762.00	33,922.00
Aug	481,850	1,104	20.00	0.05000	6.00	24,092.50	6,624.00	30,736.50
Sept	446,200	1,150	20.00	0.05000	6.00	22,310.00	6,900.00	29,230.00
Oct	387,550	1,070	20.00	0.05000	6.00	19,377.50	6,417.00	25,814.50
Nov	380,650	851	20.00	0.05000	6.00	19,032.50	5,106.00	24,158.50
Dec	295,550	794	20.00	0.05000	6.00	14,777.50	4,761.00	19,558.50
Total	**4,644,850**		**240.00**			**232,242.50**	**70,029.00**	**302,511.50**
Notes: Actual Data from Dec 2001								

Table 30B
Industrial Customer Billing - 2003 Industrial Rates

Month	2002 Energy Use kWh	Demand kW	Service Charge $	Energy Charge $/kWh	Demand Charge $/kW	Energy Cost $	Demand Cost $	Total Cost $
Month	kWh	kW	$	$/kWh	$/kW	$	$	$
Jan	287,500	805	22.00	0.05500	7.00	15,812.50	5,635.00	21,469.50
Feb	331,200	817	22.00	0.05500	7.00	18,216.00	5,715.50	23,953.50
Mar	313,950	817	22.00	0.05500	7.00	17,267.25	5,715.50	23,004.75
April	471,500	1,000	22.00	0.05500	7.00	25,932.50	7,000.00	32,954.50
May	270,250	1,000	22.00	0.05500	7.00	14,863.75	7,000.00	21,885.75
June	435,850	1,139	22.00	0.05500	7.00	23,971.75	7,969.50	31,963.25
July	542,800	1,127	22.00	0.05500	7.00	29,854.00	7,889.00	37,765.00
Aug	481,850	1,104	22.00	0.05500	7.00	26,501.75	7,728.00	34,251.75
Sept	446,200	1,150	22.00	0.05500	7.00	24,541.00	8,050.00	32,613.00
Oct	387,550	1,070	22.00	0.05500	7.00	21,315.25	7,486.50	28,823.75
Nov	380,650	851	22.00	0.05500	7.00	20,935.75	5,957.00	26,914.75
Dec	295,550	794	22.00	0.05500	7.00	16,255.25	5,554.50	21,831.75
Total	**4,644,850**		**264.00**			**255,466.75**	**81,700.50**	**337,431.25**
Percent Change								**10.4%**
Notes: Actual Data from Dec 2001								

Table 31A
Grocery Customer Billing - 2002 Commercial Rates

	Energy Use	Service Charge	Energy Charge	Energy Cost	Total Cost
Month	kWh	$	$/kWh	$	$
Jan	20,160	10.00	0.06500	1,310.40	1,320.40
Feb	21,120	10.00	0.06500	1,372.80	1,382.80
Mar	16,560	10.00	0.06500	1,076.40	1,086.40
April	21,480	10.00	0.06500	1,396.20	1,406.20
May	17,400	10.00	0.06500	1,131.00	1,141.00
June	18,720	10.00	0.06500	1,216.80	1,226.80
July	19,800	10.00	0.06500	1,287.00	1,297.00
Aug	20,520	10.00	0.06500	1,333.80	1,343.80
Sept	22,440	10.00	0.06500	1,458.60	1,468.60
Oct	22,200	10.00	0.06500	1,443.00	1,453.00
Nov	22,200	10.00	0.06500	1,443.00	1,453.00
Dec	17,640	10.00	0.06500	1,146.60	1,156.60
Total	**240,240**	**120.00**		**15,615.60**	**15,735.60**
Note: Actual Data from Dec 2001					

Table 31B
Grocery Customer Billing - 2003 Commercial Rates

	Energy Use	Service Charge	Energy Charge	Energy Cost	Total Cost
Month	kWh	$	$/kWh	$	$
Jan	20,160	12.00	0.07700	1,552.32	1,564.32
Feb	21,120	12.00	0.07700	1,626.24	1,638.24
Mar	16,560	12.00	0.07700	1,275.12	1,287.12
April	21,480	12.00	0.07700	1,653.96	1,665.96
May	17,400	12.00	0.07700	1,339.80	1,351.80
June	18,720	12.00	0.07700	1,441.44	1,453.44
July	19,800	12.00	0.07700	1,524.60	1,536.60
Aug	20,520	12.00	0.07700	1,580.04	1,592.04
Sept	22,440	12.00	0.07700	1,727.88	1,739.88
Oct	22,200	12.00	0.07700	1,709.40	1,721.40
Nov	22,200	12.00	0.07700	1,709.40	1,721.40
Dec	17,640	12.00	0.07700	1,358.28	1,370.28
Total	**240,240**	**144.00**		**18,498.48**	**18,642.48**
Percent Change					**18.5%**
Notes: Actual Data from Dec 2001					

Table 32A
Entertainment Customer Billing - 2002 Commercial Rates

Month	2002 Energy Use kWh	Service Charge $	Energy Charge $/kWh	Energy Cost $	Total Cost $
Jan	18,080	10.00	0.06500	1,175.20	1,185.20
Feb	18,880	10.00	0.06500	1,227.20	1,237.20
Mar	15,600	10.00	0.06500	1,014.00	1,024.00
April	20,400	10.00	0.06500	1,326.00	1,336.00
May	14,720	10.00	0.06500	956.80	966.80
June	17,920	10.00	0.06500	1,164.80	1,174.80
July	23,360	10.00	0.06500	1,518.40	1,528.40
Aug	21,920	10.00	0.06500	1,424.80	1,434.80
Sept	20,160	10.00	0.06500	1,310.40	1,320.40
Oct	18,880	10.00	0.06500	1,227.20	1,237.20
Nov	18,880	10.00	0.06500	1,227.20	1,237.20
Dec	18,880	10.00	0.06500	1,227.20	1,237.20
Total	**227,680**	**120.00**		**14,799.20**	**14,919.20**
Note: Actual Data from Dec 2001					

Table 32B
Grocery Customer Billing - 2003 Commercial Rates

Month	2002 Energy Use kWh	Service Charge $	Energy Charge $/kWh	Energy Cost $	Total Cost $
Jan	18,080	12.00	0.07700	1,392.16	1,404.16
Feb	18,880	12.00	0.07700	1,453.76	1,465.76
Mar	15,600	12.00	0.07700	1,201.20	1,213.20
April	20,400	12.00	0.07700	1,570.80	1,582.80
May	14,720	12.00	0.07700	1,133.44	1,145.44
June	17,920	12.00	0.07700	1,379.84	1,391.84
July	23,360	12.00	0.07700	1,798.72	1,810.72
Aug	21,920	12.00	0.07700	1,687.84	1,699.84
Sept	20,160	12.00	0.07700	1,552.32	1,564.32
Oct	18,880	12.00	0.07700	1,453.76	1,465.76
Nov	18,880	12.00	0.07700	1,453.76	1,465.76
Dec	18,880	12.00	0.07700	1,453.76	1,465.76
Total	**227,680**	**144.00**		**17,531.36**	**17,675.36**
Percent Change					**18.5%**
Notes: Actual Data from Dec 2001					

Table 33A
Norway School Customer Billing - 2002 Commercial Rates

Month	2002 Energy Use kWh	Service Charge $	Energy Charge $/kWh	Energy Cost $	Total Cost $
Jan	87,630	10.00	0.06500	5,695.95	5,705.95
Feb	121,440	10.00	0.06500	7,893.60	7,903.60
Mar	95,910	10.00	0.06500	6,234.15	6,244.15
April	95,910	10.00	0.06500	6,234.15	6,244.15
May	53,820	10.00	0.06500	3,498.30	3,508.30
June	73,140	10.00	0.06500	4,754.10	4,764.10
July	48,300	10.00	0.06500	3,139.50	3,149.50
Aug	50,370	10.00	0.06500	3,274.05	3,284.05
Sept	80,040	10.00	0.06500	5,202.60	5,212.60
Oct	84,180	10.00	0.06500	5,471.70	5,481.70
Nov	84,180	10.00	0.06500	5,471.70	5,481.70
Dec	111,780	10.00	0.06500	7,265.70	7,275.70
Total	**986,700**	**120.00**		**64,135.50**	**64,255.50**
Note: Actual Data from Dec 2001					

Table 33B
Norway School Customer Billing - 2003 Commercial Rates

Month	Energy Use kWh	Service Charge $	Energy Charge $/kWh	Energy Cost $	Total Cost $
Jan	18,080	12.00	0.07700	1,392.16	1,404.16
Feb	18,880	12.00	0.07700	1,453.76	1,465.76
Mar	15,600	12.00	0.07700	1,201.20	1,213.20
April	20,400	12.00	0.07700	1,570.80	1,582.80
May	14,720	12.00	0.07700	1,133.44	1,145.44
June	17,920	12.00	0.07700	1,379.84	1,391.84
July	23,360	12.00	0.07700	1,798.72	1,810.72
Aug	21,920	12.00	0.07700	1,687.84	1,699.84
Sept	20,160	12.00	0.07700	1,552.32	1,564.32
Oct	18,880	12.00	0.07700	1,453.76	1,465.76
Nov	18,880	12.00	0.07700	1,453.76	1,465.76
Dec	18,880	12.00	0.07700	1,453.76	1,465.76
Total	**227,680**	**144.00**		**17,531.36**	**17,675.36**
Percent Change					**18.5%**
Notes: Actual Data from Dec 2001					

11.0 Recommendations

The utility has not increased the electric rates since 1994, nearly ten years ago. Utility staff and city officials should be proud of this accomplishment. Unfortunately, this situation cannot continue indefinitely. Based on the study outcome we recommend a rate increase at this time. During recent years the present rates have allowed the utility to meet its obligations and to help fund other city functions. Utility costs are increasing and a rate increase will be required to sustain the level of past funding for utility improvements and non-utility city functions. In addition, utility management is planning some significant capital improvement projects that will help maintain electric system reliability and safety. It may be difficult to fund these projects from utility reserves and annual cash flow. The improvements could instead be funded by tax exempt revenue bonds. The proposed rate increase would provide revenues to retire the bonds.

In the study we have proposed a significant rate increase. The increase is based in part on the planned capital improvement projects. The proposed rate increase need not be made immediately but can instead be made in several increments during the next two or three years as plans for the proposed capital improvements move forward. The proposed rate changes will also help correct the revenue imbalance associated with the present rate structure. Presently, the cost of serving the residential electric customers is somewhat higher than the revenues generated by the residential rates. The commercial and industrial customers are helping to fund the utility services used by residential customers. The proposed rates will help allocate the costs of operating the utility more fairly among the customer classes.

Appendix A

Recent Rate Schedules

A-1 – Norway Municipal

A-2 – Escanaba Municipal

A-3 – Gladstone Municipal

A-1 – Norway Municipal

A-2 – Escanaba Municipal

A-3 – Gladstone Municipal

Appendix B

City of Norway Details of Revenue Statements

Appendix C

Annual Electric Utility Reports